We delivered.

2011 Annual Report

OG+E

2011 will be remembered as one of our company's best while providing more than its share of challenges. It was a year highlighted by awards and accomplishments, punctuated with blizzards, tornados and blistering summer heat that challenged our people and our equipment.

We met record demand for electricity and gathered more natural gas than ever before, always focused on executing our strategy, improving our performance and growing our business. OGE members rose to each challenge and to each opportunity. It was an award-winning performance. Their commitment to deliver in good times and bad is the foundation of our company's 110-year success. As we reflect on the year, ever mindful of where we are going and the successes we've yet to achieve, we are proud to say: We delivered.


Enogex
OG&E

I'm inspired by our members. They are driven by a commitment to operational excellence and providing exceptional customer service. They take pride in their jobs and their company, living our values and beliefs every day. Our performance is a testament to that dedication.

Positive Customer Experiences

Today's customers don't expect to be passive users of our services and won't be satisfied with a one-size-fits-all approach. They want a timely response to their needs and expect us to provide solutions, not obstacles.

Responsiveness and positive customer experiences are key drivers to achieving sustained growth and preferred partner status in the highly competitive natural gas midstream market. Our Enogex members are focused on reducing cycle time, cost and rework, which will help us meet the growing needs and expectations of our producers and end users.

At OG&E, an extensive research program helps us understand how utility customers experience our products, services and front-line interactions. They've provided a wealth of information that we've used to make process improvements, plan new products and take advantage of new technology.

Whether we're streamlining workflows or further defining engineering design standards, our commitment to the customer is paramount.

The Long, Hot Summer *Rachel Hathorn is part of OG&E's Customer Service support team. With 63 days over 100 degrees last summer, she and others worked with customers to develop payment plans. To provide short-term relief, we announced a suspension of disconnects during August. Customers were still responsible for their bills, but they didn't have to worry about having their electricity turned off during the hottest month in decades.*

Letter to Shareholders

One of a company's most important attributes for success is employees aligned around values and beliefs, vision and strategy. It's essential in an environment where change presents rich opportunities for those who remain focused and execute on a well-defined plan. At OGE, our focus has never been sharper and our members more committed to achieving our vision of being an industry leader.

2011 tested our mettle. Blizzards, tornados, 63 days of 100-plus degree temperatures, along with new environmental regulations, regulatory proceedings in Oklahoma and Arkansas, and depressed natural gas prices at Enogex challenged our resolve.

Through it all, our members met each challenge head-on and recorded one of the most successful years in our company's 110-year history.

Award-winning performance

On the financial front, the company again posted record earnings and increased its dividend for the sixth consecutive year. While weather was a primary earnings driver, we're continuing our efforts to manage costs and improve our operations, both of which contributed to improved performance.

Our solid financial performance along with sound capital investments, energy efficiency programs, smart-grid initiative and customer satisfaction received high marks from industry observers at *Electric Light and Power* magazine, which named OG&E North America's Utility of the Year. Our customers also weighed in through the annual J.D. Power and Associates survey of utility customer satisfaction. OG&E won prestigious J.D. Power awards for both residential and commercial customer satisfaction. And at Enogex, we were among the best in class in safety performance – a milestone of significant importance to me in our quest to operate incident- and injury-free.

Focused on execution

While we're proud to receive awards, we remain focused on executing the day-to-day strategy that sets us apart from others in our industry.

We continue to make progress toward our goal of not building new, incremental fossil-fired generation until 2020. Our customers are using smart meter technology to reduce demand during peak periods, which is essential as we shattered peak demand records on nine separate occasions in 2011. We're adding renewable wind energy to our system, and we're continuing to expand our high-voltage transmission system to improve reliability and open access to the regional marketplace.

At Enogex, we secured long-term acreage dedications and completed the Cordillera midstream acquisition that positions us for continued growth in the Granite Wash, one of the region's most economic natural gas plays. We saw record growth in gathering and processable volumes while maintaining first quartile reliability numbers.

Positive outlook

We continually analyze our operating environment, scanning the road ahead as we steer through the present. Our outlook for the natural gas midstream industry continues to be constructive despite short-term supply and demand imbalances. Longer term, there are opportunities for growth as power generation utilizes more natural gas, as market share in transportation grows and as new gas supplies are found in areas with little existing infrastructure. We expect the industry to require tens of billions of dollars in new infrastructure investment by 2020.

Our local economy continues to show improvement, which is reflected in our continued growth in kilowatt hour sales. We face increasingly stringent environmental regulatory policies, but continue to advocate for solutions that allow us to comply without causing significant financial impacts for our customers and shareholders.

Vision to lead

As we look to the future, we're focused on achieving our long-term earnings growth target of 5–7 percent to provide a premium valuation for our shareholders. We're committed to continued dividend growth to complement our growth in earnings. Accomplishing our return objectives requires the right mix of operating and financial capabilities working together within a high-performance culture focused on delivering value.

Our vision is to be the industry leader with a passion for helping customers, developing members and delivering shareholder value. We're moving closer to that vision each day through our keen focus on what truly sets us apart.

I thank you for your continued support and look forward to next year, when I can again say to you: We delivered.

Peter B. Delaney
Chairman, President and Chief Executive Officer

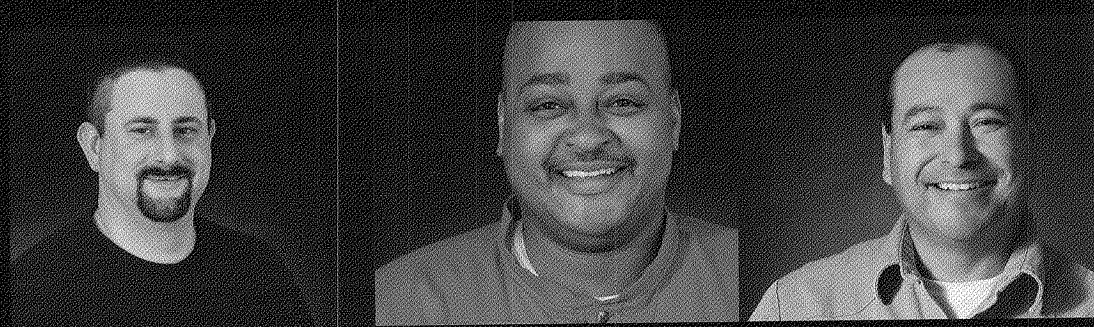
Operational Excellence

In our asset-driven businesses, it is critical that operations run smoothly and our members know what to do and how to do it safely. This requires planning and preparedness.

During 2011's blistering summer, OG&E's preventive plant maintenance program proved to be a valuable investment when all available power generation resources were needed to meet customers' increased demand. Our line crews endured long hot hours and even battled wildfires in an effort to restore power as quickly as possible.

Enogex members delivered historic gathering and transportation pipeline volumes in June and August respectively. And despite trying conditions, pipeline members turned in a safety performance that ranked among the industry's best.

We continue to make progress toward an incident- and injury-free workplace. Through determination, willpower and constant engagement, we're creating a culture where even one incident or injury is one too many.



Ingenuity and Teamwork *Redbud power plant, seen here under construction in 2002, fired up all four generating units nearly 24 hours a day on 30 consecutive days last summer. At Horseshoe Lake power plant, members installed temporary suction pumps in the nearby river when the water level dropped, threatening the units' operation. At Mustang power plant, members coordinated an effort to drill new wells when the nearby lake dried up.*

Investing for Tomorrow

OGE invested a record $1.5 billion in our businesses in 2011.

These investments helped expand our natural gas processing capacity in western Oklahoma and the Texas Panhandle to serve the area's liquids-rich plays.

We expanded our wind power portfolio with the completion of the 228-megawatt Crossroads wind farm in northwest Oklahoma, making wind power more than 10 percent of our generation mix.

We're building nearly 600 miles of new, high-voltage electric lines. These lines are essential to delivering Oklahoma's wind potential and improving regional electric system reliability.

We've also installed more than 500,000 smart meters across our service area. With the new meters we're lowering our costs and providing customers access to our new technology that will help them save money and reduce peak electricity demand.

Dependable Growth *Engineer Craig Whitnack is part of the team at Enogex's newest plant, South Canadian, commissioned in late 2011. The previously damaged Cox City plant is repaired and fully operational. We expect an expansion of the Wheeler, Texas facility to be completed in 2012, and the new McClure Plant to be commissioned in 2013.*

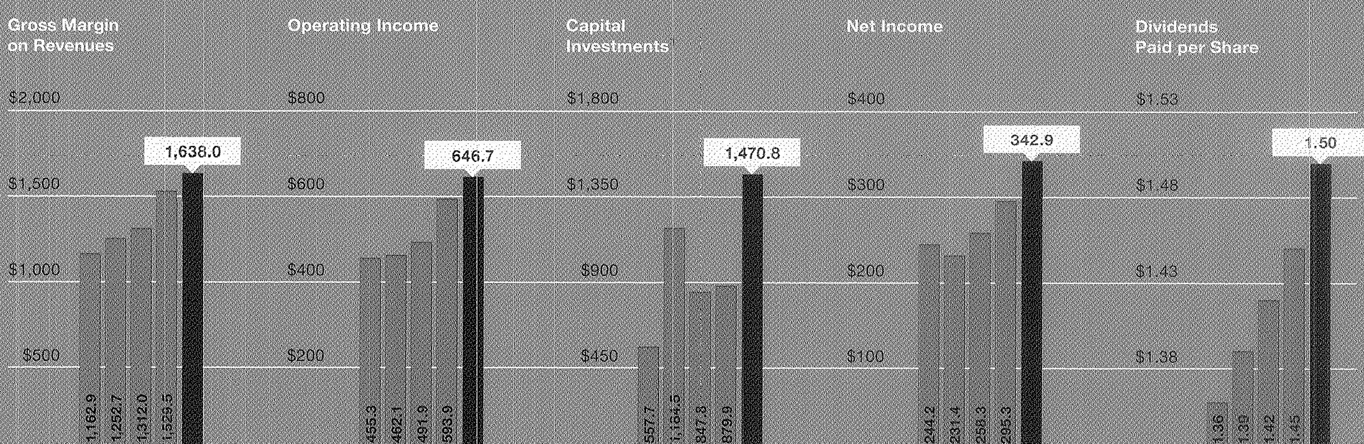

Enogex
Enogex

OGE Energy Corp. (NYSE: OGE), with headquarters in Oklahoma City, is the parent company of Oklahoma Gas and Electric Company (OG&E), a regulated electric utility, and OGE Enogex Holdings LLC, a midstream natural gas pipeline business. OGE Energy and its subsidiaries have 3,500 employees.

Oklahoma Gas and Electric Company
Oklahoma Gas and Electric Company serves approximately 789,000 retail customers in Oklahoma and western Arkansas. OG&E, with about 6,800 megawatts of capacity, generates electricity from low-sulfur Wyoming coal, natural gas and wind. OG&E's electric transmission and distribution systems cover an area of 30,000 square miles.

Enogex
Enogex operates a pipeline system in Oklahoma and Texas engaged in natural gas gathering, processing, transportation, storage and marketing. The system includes about 8,300 miles of pipe, eight natural gas processing plants and 24 billion cubic feet of natural gas storage capacity.

2011 Highlights
Dollars in millions unless noted



[1] Includes $200.4 million related to the acquisition of certain gas gathering assets.

FINANCIAL PERFORMANCE

OGE Energy Corp. Common Stock Data

	2011	2010	2009	2008	2007
Diluted earnings per share	$ 3.45	$ 2.99	$ 2.66	$ 2.49	$ 2.64
Dividends paid per share [A]	$ 1.50	$ 1.45	$ 1.42	$ 1.39	$ 1.36
Price range	$57.17 – 40.56	$46.18 – 33.87	$37.79 – 19.70	$36.23 – 19.56	$41.30 – 29.12
Price/earnings ratio – year end	16.4	15.3	13.9	10.3	13.6
Return on equity – average	13.1%	13.1%	13.1%	13.1%	14.9%
Diluted average common shares outstanding (millions)	99.2	98.9	97.2	92.8	92.5

[A] *Dividends were paid quarterly.*

Oklahoma Gas and Electric Company

(In millions except EPS, before elimination of inter-segment items)

	2011	2010	2009	2008	2007
Operating revenues	$2,212	$2,110	$1,751	$1,960	$1,835
Gross margin on revenues	$1,198	$1,110	$ 955	$ 845	$ 810
Operating income	$ 472	$ 414	$ 354	$ 278	$ 292
Net income	$ 263	$ 216	$ 200	$ 143	$ 162
Diluted earnings per share	$ 2.65	$ 2.18	$ 2.06	$ 1.54	$ 1.75
Return on equity – average	11.3%	10.3%	10.4%	9.3%	12.0%
Total electricity sales (millions of megawatt hours)	29.5	28.1	26.9	28.2	27.1

OGE Enogex Holdings LLC

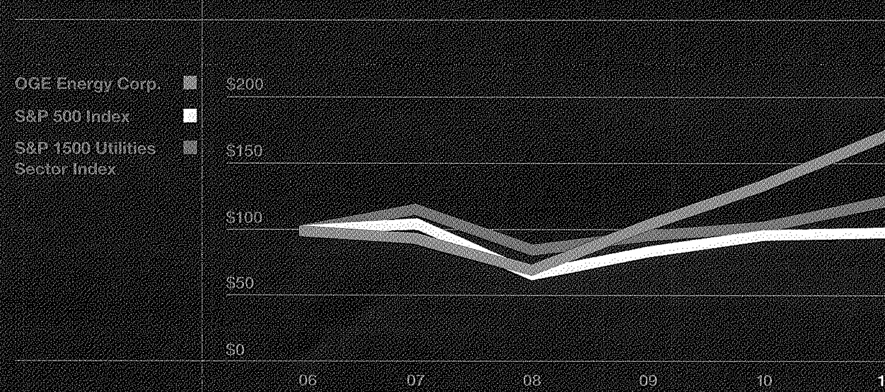
(In millions except EPS, before elimination of inter-segment items)

	2011	2010	2009	2008	2007
Operating revenues	$1,787	$1,708	$1,205	$2,239	$2,065
Gross margin on revenues	$ 441	$ 423	$ 358	$ 408	$ 353
Operating income	$ 175	$ 184	$ 139	$ 193	$ 164
Net income	$ 82	$ 91	$ 61	$ 96	$ 86
Diluted earnings per share	$ 0.83	$ 0.92	$ 0.63	$ 1.04	$ 0.93
Return on equity – average	14.0%	17.3%	13.2%	23.4%	21.9%
Pipeline throughput (TBtu/y)[A]	708	628	653	575	555

[A] *Trillion British thermal units per year.*

Cumulative Five-Year Total Return

This graph shows a five-year comparison of cumulative total returns for the Company's common stock, the S&P 500 Index and the S&P 1500 Utilities Sector Index. The graph assumes that the value of the investment in the Company's common stock and each index was $100 at Dec. 31, 2006, and that all dividends were reinvested. As of Dec. 31, 2011, the closing price of the Company's common stock on the New York Stock Exchange was $56.71.



LEADERSHIP

Board of Directors

Peter B. Delaney
Chairman, President and CEO
OGE Energy Corp., OG&E
CEO
Enogex Holdings LLC, Enogex LLC
Oklahoma City

Luke R. Corbett[3]
Former Chairman and
Chief Executive Officer,
Kerr-McGee Corporation
(oil and gas exploration and production company)
Oklahoma City

Robert Kelley[1]
President,
Kellco Investments Inc.
(private investment company)
Ardmore, Oklahoma

Robert O. Lorenz[1,2]
Retired Managing Partner,
Arthur Andersen
(accounting firm)
Oklahoma City

Leroy C. Richie[2,3]
Counsel,
Lewis & Munday, P.C.
(law firm)
Detroit, Michigan

James H. Brandi[2,3]
Retired Managing Director,
BNP Paribas Securities Corp.
(investment banking company)
New York City, New York

[1] Member of the audit committee
[2] Member of the nominating and corporate governance committee
[3] Member of the compensation committee
Red number indicates committee chairman

Wayne H. Brunetti[1,3]
Retired Chairman,
Xcel Energy Inc.
(electric utility)
Denver, Colorado

John D. Groendyke[2,3]
Chairman and
Chief Executive Officer,
Groendyke Transport, Inc.
(bulk transportation company)
Enid, Oklahoma

Kirk Humphreys[1,3]
Chairman and Manager,
The Humphreys Company, LLC
(real estate development company)
and Manager,
Carlton Landing, LLC
(real estate development company)
Oklahoma City

Linda P. Lambert[1,2]
President,
LASSO Corporation
(oil and gas investment company)
and Enertree, LLC
(oil and gas investment company)
Oklahoma City

Judy R. McReynolds[2,3]
President and
Chief Executive Officer,
Arkansas Best Corporation
(freight company)
Fort Smith, Arkansas

Senior Management

OGE Energy Corp.

Peter B. Delaney
Chairman, President and CEO
OGE Energy Corp., OG&E
CEO
Enogex Holdings LLC, Enogex LLC

Sean Trauschke
Vice President and CFO
OGE Energy Corp., OG&E
CFO
Enogex Holdings LLC, Enogex LLC

Scott Forbes
Controller and
Chief Accounting Officer
OGE Energy Corp., OG&E

Patricia D. Horn
Vice President, Governance,
Environmental, Health & Safety;
Corporate Secretary
OGE Energy Corp., OG&E
Secretary
Enogex Holdings LLC
Corporate Secretary
Enogex LLC

Gary D. Huneryager
Vice President, Internal Audits
OGE Energy Corp., OG&E

Cristina F. McQuistion
Vice President, Strategy and
Performance Improvement
OGE Energy Corp., OG&E

Max J. Myers
Treasurer
OGE Energy Corp., OG&E,
Enogex Holdings LLC

Reid V. Nuttall
Vice President,
Chief Information Officer
OGE Energy Corp., OG&E

Jerry A. Peace
Chief Risk Officer
OGE Energy Corp., OG&E

Paul L. Renfrow
Vice President, Public Affairs
and Human Resources
OGE Energy Corp., OG&E

OG&E

William J. Bullard
General Counsel
OG&E
Assistant General Counsel
OGE Energy Corp.

Philip L. Crissup
Vice President,
Utility Technical Support

Kenneth C. Johnson
Vice President,
Power Supply Operations

Jesse B. Langston
Vice President, Retail Energy

Jean C. Leger, Jr.
Vice President, Utility Operations

Michael R. Mathews
Vice President,
Power Delivery Operations

Enogex LLC

E. Keith Mitchell
President

Stephen E. Merrill
COO

Paul M. Brewer
Vice President, Operations

Jon E. Hanna
Vice President,
Business Development

John P. Laws
Vice President, Planning
and Development

Thomas L. Levescy
Controller and
Chief Accounting Officer

Ramiro F. Rangel
Vice President,
Commercial Operations
and Human Resources

OGE Energy Resources LLC

Craig R. Jimenez
President

Thank you to the following OGE Energy Corp. members for appearing in this annual report: Genique Crowder, Chris Close, Johnny Whitfield, Gary Kahler, Jon Richardson, Alba N. Weaver, Roman Chavez, Ali Wint, Virgil Thurman, Allison Eastridge, Robert Gottshall, Greg Tytenicz, Mark Martin, Craig Jimenez, Kathy Snyder, Jan Pilgrim, John Carpenter, Mike Ruby, Erika Stockton, Gloria Rudek, Doug Patterson, Rachel Hathorn, Nolan Armstrong, Dwight Matthews, Noe Flores, Anita Sindhwani, Zac Gladhill, Brian Roberson, Craig Whitnack

OGE Energy Corp. Annual Report 2011 Financial Section

(As included in the Company's Form 10-K filed with the SEC on February 16, 2012)

Forward-Looking Statements

Except for the historical statements contained herein, the matters discussed in this Annual Report, including those matters discussed in "Management's Discussion and Analysis of Financial Condition and Results of Operations," are forward-looking statements that are subject to certain risks, uncertainties and assumptions. Such forward-looking statements are intended to be identified in this document by the words "anticipate", "believe", "estimate", "expect", "intend", "objective", "plan", "possible", "potential", "project" and similar expressions. Actual results may vary materially from those expressed in forward-looking statements. In addition to the specific risk factors discussed in "Management's Discussion and Analysis of Financial Condition and Results of Operations" herein, factors that could cause actual results to differ materially from the forward-looking statements include, but are not limited to:

- General economic conditions, including the availability of credit, access to existing lines of credit, access to the commercial paper markets, actions of rating agencies and their impact on capital expenditures;
- The ability of OGE Energy Corp. ("OGE Energy" and collectively, with its subsidiaries, the "Company") and its subsidiaries to access the capital markets and obtain financing on favorable terms;
- Prices and availability of electricity, coal, natural gas and natural gas liquids ("NGL"), each on a stand-alone basis and in relation to each other as well as the processing contract mix between percent-of-liquids, percent-of-proceeds, keep-whole and fixed-fee;
- Business conditions in the energy and natural gas midstream industries;
- Competitive factors including the extent and timing of the entry of additional competition in the markets served by the Company;
- Unusual weather;
- Availability and prices of raw materials for current and future construction projects;
- Federal or state legislation and regulatory decisions and initiatives that affect cost and investment recovery, have an impact on rate structures or affect the speed and degree to which competition enters the Company's markets;
- Environmental laws and regulations that may impact the Company's operations;
- Changes in accounting standards, rules or guidelines;
- The discontinuance of accounting principles for certain types of rate-regulated activities;
- Whether Oklahoma Gas and Electric Company ("OG&E") can successfully implement its Smart Grid program to install meters for its customers and integrate the Smart Grid meters with its customer billing and other computer information systems;
- The cost of protecting assets against, or damage due to, terrorism or cyber attacks;
- Advances in technology;
- Creditworthiness of suppliers, customers and other contractual parties;
- The higher degree of risk associated with the Company's nonregulated business compared with the Company's regulated utility business; and
- Other risk factors listed in the reports filed by the Company with the Securities and Exchange Commission.

The Company undertakes no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise.

Introduction

The Company is an energy and energy services provider offering physical delivery and related services for both electricity and natural gas primarily in the south central United States. The Company conducts these activities through four business segments: (i) electric utility, (ii) natural gas transportation and storage, (iii) natural gas gathering and processing and (iv) natural gas marketing.

The electric utility segment generates, transmits, distributes and sells electric energy in Oklahoma and western Arkansas. Its operations are conducted through OG&E and are subject to regulation by the Oklahoma Corporation Commission ("OCC"), the Arkansas Public Service Commission ("APSC") and the Federal Energy Regulatory Commission ("FERC"). OG&E was incorporated in 1902 under the laws of the Oklahoma Territory. OG&E is the largest electric utility in Oklahoma and its franchised service territory includes the Fort Smith, Arkansas area. OG&E sold its retail natural gas business in 1928 and is no longer engaged in the natural gas distribution business.

OGE Enogex Holdings, LLC ("OGE Holdings," wholly-owned subsidiary of OGE Energy and parent company of Enogex Holdings LLC, and collectively, with its subsidiaries, "Enogex") is a provider of integrated natural gas midstream services. Enogex is engaged in the business of gathering, processing, transporting, storing and marketing natural gas. Most of Enogex's natural gas gathering, processing, transportation and storage assets are strategically located in the Arkoma and Anadarko basins of Oklahoma and the Texas Panhandle. Enogex's operations are organized into three business segments: (i) natural gas transportation and storage, (ii) natural gas gathering and processing and (iii) natural gas marketing. At December 31, 2011, the Company indirectly owns an 81.3 percent membership interest in Enogex Holdings LLC, the parent company of Enogex LLC and a majority-owned subsidiary of OGE Holdings ("Enogex Holdings"), which in turn owns all of the membership interests in Enogex LLC, collectively with its subsidiaries ("Enogex LLC").

Overview

Company Strategy

The Company's mission is to fulfill its critical role in the nation's electric utility and natural gas midstream pipeline infrastructure and meet individual customers' needs for energy and related services in a safe, reliable and efficient manner. The Company's corporate strategy is to continue to maintain its existing business mix and diversified asset position of its regulated electric utility business and unregulated natural gas midstream business while providing competitive energy products and services to customers primarily in the south central United States as well as seeking growth opportunities in both businesses. Additionally, the Company wants to achieve a premium valuation of its businesses relative to its peers, grow earnings per share with a stable earnings pattern, create a high performance culture and achieve desired outcomes with target stakeholders.

OG&E is focused on increased investment to preserve system reliability and meet load growth by adding and maintaining infrastructure equipment and replacing aging transmission and distribution systems. OG&E is focused on maintaining strong regulatory and legislative relationships for the long-term benefit of its customers. In an effort to encourage more efficient use of electricity, OG&E is also providing energy management solutions to its customers through the Smart Grid program that utilizes newer technology to improve operational and environmental performance and promote demand-side management programs. If these initiatives are successful, OG&E believes it may be able to defer the construction or acquisition of any incremental fossil fuel generation capacity until 2020. As the Smart Grid platform matures, OG&E anticipates providing new products and services to its customers. In addition, OG&E is also pursuing additional transmission-related opportunities within the Southwest Power Pool ("SPP"). OG&E is customer focused and strives to provide excellent customer service.

Enogex's business plan entails growing its businesses and providing attractive financial returns through efficient operations and effective commercial management of its assets, capturing growth opportunities through expansion projects, increased utilization of existing assets and through acquisitions in and around its footprint. In addition, Enogex is seeking to geographically diversify its gathering, processing and transportation businesses principally by expanding into other areas that are complementary with the Company's capabilities. Enogex expects to accomplish this diversification by undertaking organic growth projects and through acquisitions.

The Company's financial objectives include a long-term annual earnings growth rate of five to seven percent on a weather-normalized basis, maintaining a strong credit rating as well as increasing the dividend to meet the Company's dividend payout objectives. The Company's target payout ratio is to pay out dividends no more than 60 percent of its normalized earnings on an annual basis. The target payout ratio has been determined after consideration of numerous factors, including the largely retail composition of the Company's shareholder base, the Company's financial position, the Company's growth targets, the composition of the Company's assets and investment opportunities. The Company believes it can accomplish these financial objectives by, among other things, pursuing multiple avenues to build its business, maintaining a diversified asset position, continuing to develop a wide range of skills to succeed with changes in its industries, providing products and services to customers efficiently, managing risks effectively and maintaining strong regulatory and legislative relationships.

Summary of Operating Results

2011 Compared to 2010

Net income attributable to OGE Energy was $342.9 million, or $3.45 per diluted share, in 2011 as compared to $295.3 million, or $2.99 per diluted share, in 2010. Included in net income attributable to OGE Energy in 2010 was a one-time, non-cash charge of $11.4 million, or $0.11 per diluted share, related to the elimination of the tax deduction for the Medicare Part D subsidy (as previously reported in the Company's Form 10-Q for the quarter ended March 31, 2011). The increase in net income attributable to OGE Energy of $47.6 million, or 16.1 percent, or $0.46 per diluted share, in 2011 as compared to 2010 was primarily due to:

- An increase in net income at OG&E of $47.6 million, or 22.1 percent, or $0.47 per diluted share of the Company's common stock, primarily due to a higher gross margin primarily from warmer weather in OG&E's service territory partially offset by higher other operation and maintenance expense, higher interest expense and higher income tax expense. Income tax expense was higher due to higher pre-tax income which more than offset the effects of the Medicare Part D subsidy discussed above;
- A decrease in net income at Enogex of $8.9 million, or 9.8 percent, or $0.09 per diluted share of the Company's common stock, primarily due to higher other operation and maintenance expense and the equity sale of a membership interest in Enogex Holdings to Bronco Midstream Holdings, LLC, Bronco Midstream Holdings II, LLC, (collectively the "ArcLight group") partially offset by a higher gross margin primarily from increased gathered volumes associated with ongoing expansion projects and higher NGLs prices, the recognition of a gain related to the sale of the Harrah processing plant and the associated Wellston and Davenport gathering assets, lower interest expense and lower income tax expense related to the Medicare Part D subsidy discussed above; and
- An increase in net income at OGE Energy of $8.9 million, or 77.4 percent, or $0.08 per diluted share of the Company's common stock, primarily due to lower other operation and maintenance expense, a decrease in charitable contributions in 2011 and a higher income tax benefit related to the Medicare Part D subsidy discussed above.

Timing Item

Enogex's net income in 2011 was $82.2 million, which included a loss of $2.6 million resulting from recording OGE Energy Resources LLC, wholly-owned subsidiary of Enogex LLC ("OER"), natural gas storage inventory at the lower of cost or market value. The offsetting gains from the sale of withdrawals from inventory are expected to be realized during the first quarter of 2012.

2010 Compared to 2009

Net income attributable to OGE Energy was $295.3 million, or $2.99 per diluted share, in 2010 as compared to $258.3 million, or $2.66 per diluted share, in 2009. Included in net income attributable to OGE Energy in 2010 was a one-time, non-cash charge of $11.4 million, or $0.11 per diluted share, related to the elimination of the tax deduction for the Medicare Part D subsidy (as previously reported in the Company's Form 10-Q for the quarter ended March 31, 2011). The increase in net income attributable to OGE Energy of $37.0 million, or 14.3 percent, or $0.33 per diluted share, in 2010 as compared to 2009 was primarily due to:

- An increase in net income at OG&E of $15.3 million or 7.6 percent, or $0.12 per diluted share of the Company's common stock, due to a higher gross margin primarily due to rate increases and riders and warmer weather in OG&E's service territory partially offset by higher other operation and maintenance expense, higher depreciation and amortization expense and higher income tax expense mainly attributable to higher pre-tax income and the elimination of the tax deduction for the Medicare Part D subsidy discussed above;
- An increase in net income at Enogex of $29.8 million or 48.6 percent, or $0.29 per diluted share of the Company's common stock, due to a higher gross margin primarily due to higher processing spreads, higher NGLs prices, higher natural gas prices and increased volumes partially offset by higher other operation and maintenance expense and higher income tax expense mainly attributable to higher pre-tax income and the elimination of the tax deduction for the Medicare Part D subsidy discussed above; and
- An increase in the net loss at OGE Energy of $8.1 million, or $0.08 per diluted share of the Company's common stock, due to higher other expense primarily attributable to an increase in charitable contributions to OGE Energy's charitable giving foundation in 2010 and higher income tax expense mainly attributable to the elimination of the tax deduction for the Medicare Part D subsidy discussed above partially offset by lower interest expense primarily due to lower average commercial paper borrowings and a lower average interest rate in 2010.

Recent Developments and Regulatory Matters

Global Climate Change, Environmental Concerns and Related Opportunities

It is uncertain at this time whether, and in what form, Congress will adopt legislation to restrict greenhouse gas emissions. In the absence of such legislation, the U.S. Environmental Protection Agency ("EPA") has taken steps to regulate greenhouse gas emissions. Future legislation or rules could require reductions of carbon dioxide and other greenhouse gas emissions from generation facilities. This could result in significant changes to the Company's operations, significant capital expenditures by the Company and a significant increase in the Company's cost of conducting business. The OG&E service territory is in central Oklahoma and borders one of the nation's best wind resource areas. Uncertainty surrounding global climate change and environmental concerns related to new coal-fired generation development is changing the mix of the potential sources of new generation in the region. Adoption of renewable portfolio standards would be expected to increase the region's reliance on wind generation and other renewables. The Company has leveraged its advantageous geographic position to develop renewable energy resources and transmission to deliver the renewable energy. In January 2012, OG&E's Crossroads wind farm in Dewey County, Oklahoma ("Crossroads") was placed in service and added to OG&E's wind power portfolio, which now includes potential wind generation of up to of 780 megawatts ("MW") (including wind power purchase agreements). In addition, the SPP regional transmission organization has begun to address the relative lack of transmission lines capable of bringing renewable energy out of the wind resource area in western Oklahoma, the Texas panhandle and western Kansas to load centers by planning for more transmission to be built in the area. In addition to significantly increasing overall system reliability, these new transmission resources should provide greater access to additional wind resources that are currently constrained due to existing transmission delivery constraints.

OG&E Crossroads Wind Farm

On July 29, 2010, OG&E received an order from the OCC authorizing OG&E to recover from Oklahoma customers the cost to construct Crossroads, with the rider being implemented as the individual turbines are placed in service. The Crossroads wind farm was fully in service in January 2012. As part of this project, on June 16, 2011, OG&E entered into an interconnection agreement with the SPP for Crossroads which allowed Crossroads to interconnect at 227.5 MWs.

OG&E 2011 Oklahoma Rate Case Filing

As part of the Joint Stipulation and Settlement Agreement reached in OG&E's 2009 Oklahoma rate case filing, the parties agreed that OG&E would file a rate case on or before June 30, 2011. On May 27, 2011, OG&E requested an extension until the end of July 2011 for filing the Oklahoma rate case. On July 28, 2011, OG&E filed its application with the OCC requesting an annual rate increase of $73.3 million, or a 4.3 percent increase in its rates. OG&E is requesting a return on equity of 11.00 percent based on a common equity percentage of 53 percent. Each 0.10 percent change in the requested return on equity affects the requested rate increase by $3.0 million. In its application, OG&E seeks to recover increases in its operating costs and to begin earning on approximately $500 million of new capital investments made on behalf of its Oklahoma customers during the previous two and one-half years. On November 9, 2011, the OCC Staff recommended a $6.2 million annual rate decrease based on a return on equity of 9.81 percent and a common equity percentage of 53 percent. The staff of the Oklahoma Attorney General recommended a return on equity of 9.818 percent and a common equity percentage of 49.5 percent. The staff of the Oklahoma Attorney General did not recommend a specific revenue requirement, but OG&E believes that adoption of the staff of the Oklahoma Attorney General's recommendations would result in a rate decrease. The Oklahoma Industrial Electric Consumers recommended a $56 million annual rate decrease based on a return on equity of 9.5 percent and a common equity percentage of 48 percent. OG&E filed rebuttal testimony on November 29, 2011 on the revenue requirement testimony filed by the parties on November 9, 2011. On November 16, 2011, the parties filed cost-of-service and rate design testimony and OG&E filed rebuttal testimony in those areas on December 2, 2011. The hearing in this matter began on December 13, 2011. OG&E expects to receive an order from the OCC in the first quarter of 2012.

OG&E Contract and Wind Energy Purchase Agreement Filing

On December 1, 2011, OG&E filed an application with the OCC requesting approval of a 20-year agreement that is intended to provide wind power to help meet the current and future power generation needs of Oklahoma State University. The project calls for OG&E to contract with NextEra Energy to build a 60 MW wind farm near Blackwell, Oklahoma, to support the Oklahoma State University project in which NextEra will build, own and operate the wind farm and OG&E will purchase the electric output. A procedural schedule has not yet been established in this matter. OG&E expects to receive a decision from the OCC in the first quarter of 2012.

Enogex FERC Section 311 2009 Rate Case

On March 27, 2009, Enogex filed a petition for rate approval with the FERC to set the maximum rates for its new firm East Zone Section 311 transportation service and to revise the rates for its existing East and West Zone interruptible Section 311 transportation service. In anticipation of offering this new service, Enogex had filed with the FERC, as required by the FERC's regulations, a revised Statement of Operating Conditions Applicable to Transportation Services to describe the terms, conditions and operating arrangements for the new service. Enogex made the Statement of Operating Conditions filing on February 27, 2009. Enogex began offering firm East Zone Section 311 transportation service on April 1, 2009. The revised East and West Zone zonal rates for the Section 311 interruptible transportation service became effective June 1, 2009. The rates for the firm East Zone Section 311 transportation service and the increase in the rates for East and West Zone and interruptible Section 311 service were collected, subject to refund, pending the FERC approval of the proposed rates. A number of parties intervened in both the rate case and the Statement of Operating Conditions filing and some additionally filed protests. On January 4, 2010, the FERC Staff submitted an offer proposing various adjustments to Enogex's filed cost of service. On April 27, 2010, Enogex submitted comments to the FERC Staff stating that it would agree to the offer, contingent upon all parties agreeing to support or not oppose. On October 4, 2011, Enogex filed a settlement agreement with the FERC which included a proposed refund to shippers of $2.1 million related to the increase in the rates for East and West Zone and interruptible Section 311 service which were collected, subject to refund, pending the FERC approval of the proposed rates. This refund was made to shippers in January 2012. On December 16, 2011, the FERC issued an order approving the settlement agreement. See Note 17 of Notes to Consolidated Financial Statements for a further discussion.

Enogex Cox City Plant Fire

On December 8, 2010, a fire occurred at Enogex's Cox City natural gas processing plant destroying major components of one of the four processing trains, representing 120 million cubic feet per day ("MMcf/d") of the total 180 MMcf/d of capacity, at that facility. Gas volumes normally processed at the Cox City plant were diverted to other facilities or bypassed around Enogex's system to accommodate production and all of the impacted gathered volumes were back online in December 2010. The damaged train was replaced and the facility was returned to full service in September 2011. The total cost necessary to return the facility back to full service was $29.6 million. While Enogex believes that the costs in excess of the $10 million deductible should be reimbursed by insurance, the matter is currently being negotiated with the insurance company and Enogex cannot predict the precise outcome of these negotiations or the timing associated with the recovery. In the fourth quarter of 2011, Enogex received a partial insurance reimbursement of $7.4 million and recognized a gain of $3.0 million on insurance proceeds. Enogex expects to receive additional reimbursement of portions of the costs in 2012. Enogex will recognize insurance recoveries in earnings as the insurance claims are resolved.

Enogex Contract Conversion

In August 2011, Enogex and one of its five largest customers entered into new agreements, effective July 1, 2011, relating to the customer's gathering and processing volumes on the Oklahoma portion of Enogex's system. The effect of this new arrangement is that (i) the acreage dedicated by the customer to Enogex for gathering and processing in Oklahoma has been increased for an extended term and (ii) the processing arrangement has been converted from keep-whole to fixed fee. This customer's converted volumes represented 8.4 percent of total inlet volumes from July 1, 2011 to December 31, 2011. Also, as a result of this transaction and as part of the new agreements, Enogex recorded $6.4 million in Deferred Revenues on the Company's Consolidated Balance Sheet at December 31, 2011. Processing revenues under the agreements are recognized based on the estimated average fee per million British thermal unit ("MMBtu") processed over the life of the agreements. Enogex expects to record additional deferred revenues during 2012.

Enogex Western Oklahoma/Texas Panhandle Gathering and Processing System Expansions

As previously reported, gathering and processing volumes grew at a slower pace during the fourth quarter of 2011 than Enogex had anticipated. Enogex currently expects that this slower growth will continue during 2012. Despite this slower volume growth, Enogex still anticipates the need for additional processing capacity.

Enogex constructed a new 200 MMcf/d cryogenic processing plant in Canadian County, Oklahoma. The new plant, which has inlet and residue compression and is supported by the installation of 31 miles of 20-inch gathering pipeline, as well as 11 miles of 24-inch transmission pipeline providing takeaway capacity from the plant tailgate, was placed in service in December 2011. The total capital expenditures associated with this project were $140 million.

Enogex expects to expand its cryogenic processing plant currently under construction in Wheeler County, Texas from a processing capacity of 120 MMcf/d to 200 MMcf/d with the installation of additional residue compression facilities. The initial processing capacity of 120 MMcf/d is expected to be in service at the beginning of the third quarter of 2012, and the additional processing capacity is expected to be in service by the end of the third quarter of 2012. The new plant will be supported by the installation of 9,400 horsepower of field compression. The total capital expenditures associated with this project are expected to be $140 million.

In support of significant long-term acreage dedications from its customers in the area, Enogex continues to expand its gathering infrastructure in four counties of western Oklahoma. These expansions are planned to occur in phases, with the initial phase calling for the installation of 47,980 horsepower of low pressure compression and over 300 miles of gathering pipe across the area. This infrastructure is expected to be constructed throughout 2012 and 2013. The total capital expenditures associated with these expansions projects are expected to be $240 million.

Enogex expects to install a 200 MMcf/d cryogenic processing plant in Custer County, Oklahoma. The new plant will be supported by 6,000 horsepower of inlet compression and 25 miles of transmission pipeline. This plant is expected to be in service by the end of the third quarter of 2013. The total capital expenditures associated with this project are expected to be $135 million.

Gas Gathering Acquisitions

On September 23, 2011, Enogex entered into the following agreements: an agreement with Cordillera Energy Partners III, LLC ("Cordillera"), Oxbow Midstream, LLC ("Oxbow") and West Canadian Midstream LLC pursuant to which Enogex agreed to acquire 100 percent of the membership interest in Roger Mills Gas Gathering, LLC, an Oklahoma limited liability company that owns an approximately 60-mile natural gas gathering system located in Roger Mills County and Ellis County, Oklahoma; an agreement with Cordillera and Oxbow pursuant to which Enogex agreed to acquire an approximately 30-mile natural gas gathering system located in Roger Mills County, Oklahoma; and agreements with Cordillera and other producers pursuant to which such producers agreed to provide Enogex with long-term acreage dedication in the area served by the gathering systems encompassing approximately 100,000 net acres. The gathering systems are located in the Granite Wash area. The aggregate purchase price for these transactions was $200.4 million which was paid in cash primarily from contributions from OGE Energy and the ArcLight group (as discussed in Note 4 of Notes to Consolidated Financial Statements) as well as cash generated from operations and bank borrowings. The transactions closed on November 1, 2011. Enogex believes that the transactions will provide Enogex with key new opportunities in the Granite Wash area. See Note 3 of Notes to Consolidated Financial Statements for a further discussion.

In support of the acquisitions described above, Enogex plans to construct 20 miles of 16-inch gathering pipe and over 11,000 horsepower of low pressure compression in 2012. The total capital expenditures for these projects are expected to be $55 million.

2012 Outlook

The Company's 2012 consolidated earnings guidance will be provided following a final order in the Oklahoma general rate case. The Company anticipates the final order during March 2012. The 2012 earnings guidance for Enogex and the related key assumptions for such guidance, as well as 2013 volume projections, are listed below.

2012 Earnings Guidance and Key Assumptions for Enogex

The Company projects Enogex to earn approximately $80 million to $95 million, or $0.80 to $0.95 per average diluted share, in 2012 net of noncontrolling interest. The guidance assumes approximately 99.9 million average diluted shares outstanding. The key factors and assumptions include:

- Total Enogex anticipated gross margin of between $500 million and $515 million. The gross margin assumption includes:
- Transportation, storage and marketing gross margin contribution of between $140 million and $155 million, of which 80 percent is attributable to the transportation business;
- Gathering and processing gross margin contribution of between $355 million and $365 million, of which 62 percent is attributable to the processing business;
- Key factors affecting the gathering and processing gross margin forecast are:
  - Assumed increase of six to 10 percent in gathered volumes over 2011;
  - Assumed increase of approximately 15 percent in processable* volumes over 2011;
  - At the midpoint of Enogex's gathering and processing assumption Enogex has assumed:
    - Processing contract mix of 42 percent fixed-fee, 25 percent percent-of-liquids, 17 percent percent-of-proceeds and 16 percent keep-whole;
    - Weighted average natural gas price of $2.70 per MMBtu in 2012;
    - Realized weighted average NGLs price of $1.04 per gallon in 2012; and
    - Average price per gallon of condensate of $2.12 in 2012;
- Enogex has assumed operating expenses of $295 million to $305 million, with operation and maintenance expenses comprising 58 percent of the total;
- Interest expense of $31 million to $33 million;
- An effective tax rate of 38 percent; and
- ArcLight group will own approximately 19 percent of Enogex Holdings by the end of 2012.

2013 Volume Projections for Enogex

- Assumed increase of 10 to 15 percent in gathered volumes over 2012; and
- Assumed increase of approximately 15 percent in processable* volumes over 2012.

* *Processable volumes include condensate volumes which are captured in the gathering pipeline and therefore not included in plant inlet volumes.*

Results of Operations

The following discussion and analysis presents factors that affected the Company's consolidated results of operations for the years ended December 31, 2011, 2010 and 2009 and the Company's consolidated financial position at December 31, 2011 and 2010. The following information should be read in conjunction with the Consolidated Financial Statements and Notes thereto. Known trends and contingencies of a material nature are discussed to the extent considered relevant.

(In millions, except per share data, year ended December 31)	2011	2010	2009
Operating income	**$ 646.7**	$ 593.9	$ 491.9
Net income attributable to OGE Energy	**$ 342.9**	$ 295.3	$ 258.3
Basic average common shares outstanding	**97.9**	97.3	96.2
Diluted average common shares outstanding	**99.2**	98.9	97.2
Basic earnings per average common share attributable to OGE Energy common shareholders	**$ 3.50**	$ 3.03	$ 2.68
Diluted earnings per average common share attributable to OGE Energy common shareholders	**$ 3.45**	$ 2.99	$ 2.66
Dividends declared per common share	**$1.5175**	$1.4625	$1.4275

In reviewing its consolidated operating results, the Company believes that it is appropriate to focus on operating income as reported in its Consolidated Statements of Income as operating income indicates the ongoing profitability of the Company excluding the cost of capital and income taxes.

(In millions, year ended December 31)	2011	2010	2009
Operating income (loss) by business segment			
OG&E (Electric Utility)	**$472.3**	$413.7	$354.1
Enogex (Natural Gas Midstream Operations)			
Transportation and storage	**74.4**	72.6	85.7
Gathering and processing	**118.7**	123.9	60.2
Marketing	**(18.1)**	(15.0)	(7.5)
Other operations[(A)]	**(0.6)**	(1.3)	(0.6)
Consolidated operating income	**$646.7**	$593.9	$491.9

[(A)] *Other Operations primarily includes the operations of the holding company and consolidating eliminations.*

The following operating income analysis by business segment includes intercompany transactions that are eliminated in the Consolidated Financial Statements.

(Dollars in millions, year ended December 31)	2011	2010	2009
OG&E (Electric Utility)			
Operating revenues	**$2,211.5**	$2,109.9	$1,751.2
Cost of goods sold	**1,013.5**	1,000.2	796.3
Gross margin on revenues	**1,198.0**	1,109.7	954.9
Other operation and maintenance	**436.0**	418.1	348.0
Depreciation and amortization	**216.1**	208.7	187.4
Impairment of assets	**–**	–	0.3
Taxes other than income	**73.6**	69.2	65.1
Operating income	**472.3**	413.7	354.1
Interest income	**0.5**	0.1	1.1
Allowance for equity funds used during construction	**20.4**	11.4	15.1
Other income	**8.0**	6.5	20.4
Other expense	**8.4**	1.6	6.7
Interest expense	**111.6**	103.4	93.6
Income tax expense	**117.9**	111.0	90.0
Net income	**$ 263.3**	$ 215.7	$ 200.4
Operating revenues by classification			
Residential	**$ 943.5**	$ 894.8	$ 717.9
Commercial	**531.3**	521.0	439.8
Industrial	**216.0**	212.5	172.1
Oilfield	**165.1**	162.8	132.6
Public authorities and street light	**207.4**	200.8	167.7
Sales for resale	**65.3**	65.8	53.6
Provision for rate refund	**–**	–	(0.6)
System sales revenues[(A)]	**2,128.6**	2,057.7	1,683.1
Off-system sales revenues[(B)]	**36.2**	21.7	31.8
Other	**46.7**	30.5	36.3
Total operating revenues	**$2,211.5**	$2,109.9	$1,751.2
Megawatt-hour ("MWH") sales by classification (in millions)			
Residential	**9.9**	9.6	8.7
Commercial	**6.9**	6.7	6.4
Industrial	**3.9**	3.8	3.6
Oilfield	**3.2**	3.1	2.9
Public authorities and street light	**3.2**	3.0	3.0
Sales for resale	**1.4**	1.4	1.3
System sales	**28.5**	27.6	25.9
Off-system sales	**1.0**	0.5	1.0
Total sales	**29.5**	28.1	26.9
Number of customers	**789,146**	782,558	776,550
Weighted-average cost of energy per kilowatt-hour (cents)			
Natural gas	**4.328**	4.638	3.696
Coal	**2.064**	1.911	1.747
Total fuel	**2.897**	3.012	2.474
Total fuel and purchased power	**3.215**	3.309	2.760
Degree days[(C)]			
Heating – Actual	**3,359**	3,528	3,456
Heating – Normal	**3,631**	3,631	3,631
Cooling – Actual	**2,776**	2,328	1,860
Cooling – Normal	**1,911**	1,911	1,911

[(A)] *Sales to OG&E's customers.*

[(B)] *Sales to other utilities and power marketers*

[(C)] *Degree days are calculated as follows: The high and low degrees of a particular day are added together and then averaged. If the calculated average is above 65 degrees, then the difference between the calculated average and 65 is expressed as cooling degree days, with each degree of difference equaling one cooling degree day. If the calculated average is below 65 degrees, then the difference between the calculated average and 65 is expressed as heating degree days, with each degree of difference equaling one heating degree day. The daily calculations are then totaled for the particular reporting period.*

2011 Compared to 2010

OG&E's operating income increased $58.6 million, or 14.2 percent, in 2011 as compared to 2010 primarily due to a higher gross margin partially offset by higher other operation and maintenance expense.

Gross Margin

Gross margin was $1,198.0 million in 2011 as compared to $1,109.7 million in 2010, an increase of $88.3 million, or 8.0 percent. The gross margin increased primarily due to:

- Warmer weather in OG&E's service territory, which increased the gross margin by $27.4 million;
- Increased price variance, which included revenues from various rate riders, including OG&E's transmission line from Oklahoma City, Oklahoma to Woodward, Oklahoma ("Windspeed") rider, the Oklahoma demand program rider, the Smart Grid rider, the system hardening rider, the Oklahoma storm recovery rider, the Crossroads rider and the OU Spirit rider, and higher revenues from sales and customer mix, which increased the gross margin by $23.9 million;
- Higher transmission revenue primarily due to the inclusion of construction work in progress in transmission rates for specific FERC approved projects that previously accrued allowance for funds used during construction, which increased the gross margin by $15.3 million;
- New customer growth in OG&E's service territory, which increased the gross margin by $13.1 million;
- Revenues from the Arkansas rate increase, which increased the gross margin by $6.0 million;
- Higher demand and related revenues by non-residential customers in OG&E's service territory, which increased the gross margin by $5.0 million; and
- Higher revenues related to the renewal of the Arkansas Valley Electric Cooperative contract (see Note 17 of Notes to Consolidated Financial Statements), which increased the gross margin by $3.1 million.

These increases in the gross margin were partially offset by a credit to customers related to the settlement of OG&E's 2009 fuel adjustment clause review (see Note 17 of Notes to Consolidated Financial Statements), which decreased the gross margin by $5.7 million.

Cost of goods sold for OG&E consists of fuel used in electric generation, purchased power and transmission related charges. Fuel expense was $775.0 million in 2011 as compared to $771.0 million in 2010, an increase of $4.0 million, or 0.5 percent, primarily due to higher generation primarily due to warmer weather in OG&E's service territory. OG&E's electric generating capability is fairly evenly divided between coal and natural gas and provides for flexibility to use either fuel to the best economic advantage for OG&E and its customers. In 2011, OG&E's fuel mix was 58 percent coal, 39 percent natural gas and three percent wind. In 2010, OG&E's fuel mix was 55 percent coal, 42 percent natural gas and three percent wind. Purchased power costs were $230.7 million in 2011 as compared to $226.5 million in 2010, an increase of $4.2 million, or 1.9 percent, primarily due to an increase in short-term power purchases partially offset by a decrease in purchases in the energy imbalance service market and a decrease in cogeneration cost.

Variances in the actual cost of fuel used in electric generation and certain purchased power costs, as compared to the fuel component included in the cost-of-service for ratemaking, are passed through to OG&E's customers through fuel adjustment clauses. The fuel adjustment clauses are subject to periodic review by the OCC, the APSC and the FERC. The OCC, the APSC and the FERC have authority to review the appropriateness of gas transportation charges or other fees OG&E pays to Enogex.

Operating Expenses

Other operation and maintenance expenses were $436.0 million in 2011 as compared to $418.1 million in 2010, an increase of $17.9 million, or 4.3 percent. The increase in other operation and maintenance expenses was primarily due to:

- An increase of $15.5 million allocated from the holding company primarily related to payroll and benefits expense, contract technical and construction services and contract professional services;
- An increase of $12.1 million in salaries and wages expense primarily due to salary increases in 2011, increased incentive compensation expense and increased overtime expense primarily due to storms in April and August 2011;
- An increase of $4.6 million in other marketing and sales expense related to demand-side management initiatives, which expenses are being recovered through a rider;
- An increase of $3.1 million in uncollectible expense;
- An increase of $1.6 million in fleet transportation expense primarily due to higher fuel costs in 2011;
- An increase of $1.3 million in temporary labor expense; and
- An increase of $1.2 million in SPP administration fees.

These increases in other operation and maintenance expenses were partially offset by:

- A decrease of $9.8 million in employee benefits expense primarily due to a decrease in postretirement benefits expense related to amendments to the Company's retiree medical plan adopted in January 2011 (see Note 14 of Notes to Consolidated Financial Statements) partially offset by a modification to OG&E's pension tracker and a decrease in worker's compensation accruals in 2011;
- A decrease of $5.0 million in injuries and damages expense primarily due to higher reserves on claims in 2010; and
- A decrease of $2.9 million related to decreased spending on vegetation management partially related to system hardening, which expenses are being recovered through a rider.

Additional Information

Allowance for Equity Funds Used During Construction. Allowance for equity funds used during construction was $20.4 million in 2011 as compared to $11.4 million in 2010, an increase of $9.0 million, or 78.9 percent, primarily due to higher levels of construction costs for Crossroads.

Other Income. Other income was $8.0 million in 2011 as compared to $6.5 million in 2010, an increase of $1.5 million, or 23.1 percent. The increase in other income was primarily due to a benefit of $5.6 million associated with the tax gross-up of allowance for equity funds used during construction partially offset by increased losses of $4.2 million recognized in the guaranteed flat bill program in 2011 from higher than expected usage resulting from warmer weather.

Other Expense. Other expense was $8.4 million in 2011 as compared to $1.6 million in 2010, an increase of $6.8 million, primarily due to an increase in charitable contributions of $6.4 million as the holding company made the charitable contributions in 2010.

Interest Expense. Interest expense was $111.6 million in 2011 as compared to $103.4 million in 2010, an increase of $8.2 million, or 7.9 percent, primarily due to a $14.0 million increase related to the issuance of long-term debt in June 2010 and May 2011. This increase in interest expense was partially offset by:

- A $4.9 million decrease in interest expense due to a higher allowance for borrowed funds used during construction primarily due to construction costs for Crossroads; and
- A $1.4 million decrease in interest expense in 2011 due to interest to customers related to the fuel over recovery balance in 2010.

Income Tax Expense. Income tax expense was $117.9 million in 2011 as compared to $111.0 million in 2010, an increase of $6.9 million, or 6.2 percent. The increase in income tax expense was primarily due to higher pre-tax income in 2011 as compared to 2010. This increase in income tax expense was partially offset by:

- The one-time, non-cash charge in 2010 for the elimination of the tax deduction for the Medicare Part D subsidy;
- The write-off of previously recognized Oklahoma investment tax credits in 2010 primarily due to expenditures no longer eligible for the Oklahoma investment tax credit related to the change in the tax method of accounting for capitalization of repair expenditures; and
- Higher Oklahoma investment tax credits in 2011 as compared to 2010.

2010 Compared to 2009

OG&E's operating income increased $59.6 million, or 16.8 percent, in 2010 as compared to 2009 primarily due to a higher gross margin partially offset by higher other operation and maintenance expense and higher depreciation and amortization expense.

Gross Margin

Gross margin was $1,109.7 million in 2010 as compared to $954.9 million in 2009, an increase of $154.8 million, or 16.2 percent. The gross margin increased primarily due to:

- Increased price variance, which included revenues from various rate riders, including the Windspeed rider, the OU Spirit rider, the Oklahoma demand program rider and the Smart Grid rider, and higher revenues from the sales and customer mix, which increased the gross margin by $74.5 million;
- Warmer weather in OG&E's service territory resulting in a 25 percent increase in cooling degree days, which increased the gross margin by $46.8 million;
- Revenue from the full year effect of the August 2009 Oklahoma rate increase, which increased the gross margin by $24.1 million;
- Higher demand and related revenues by non-residential customers in OG&E's service territory, which increased the gross margin by $6.9 million;
- New customer growth in OG&E's service territory, which increased the gross margin by $6.7 million; and
- Revenues from the full year effect of the June 2009 Arkansas rate increase, which increased the gross margin by $3.5 million.

These increases in the gross margin were partially offset by lower other revenues due to fewer transmission requests from others on OG&E's system, which decreased the gross margin by $7.7 million.

Fuel expense was $771.0 million in 2010 as compared to $618.5 million in 2009, an increase of $152.5 million, or 24.7 percent, primarily due to higher natural gas prices and increased natural gas generation due to ongoing maintenance at some of OG&E's coal-fired power plants. OG&E's electric generating capability is fairly evenly divided between coal and natural gas and provides for flexibility to use either fuel to the best economic advantage for OG&E and its customers. In 2010, OG&E's fuel mix was 55 percent coal, 42 percent natural gas and three percent wind. In 2009, OG&E's fuel mix was 60 percent coal, 38 percent natural gas and two percent wind. Purchased power costs were $226.5 million in 2010 as compared to $176.6 million in 2009, an increase of $49.9 million, or 28.3 percent, primarily due to an increase in purchases in the energy imbalance service market to meet OG&E's generation load requirements and an increase in short-term power agreements resulting in short-term spot market purchases.

Operating Expenses

Other operation and maintenance expenses were $418.1 million in 2010 as compared to $348.0 million in 2009, an increase of $70.1 million, or 20.1 percent. The increase in other operation and maintenance expenses was primarily due to:

- An increase of $16.2 million in contract technical and construction services and an increase of $5.2 million in materials and supplies expense primarily attributable to increased spending for ongoing maintenance at some of OG&E's power plants in 2010 as compared to 2009;
- An increase of $16.2 million in employee benefits expense primarily due to an increase in postretirement benefits due to an increase in medical costs and changes in actuarial assumptions in 2010, a reclassification in May 2009 of 2006 and 2007 pension settlement costs to a regulatory asset, as prescribed in the Arkansas rate case settlement, and an increase in pension expense due to an increase in the amount deferred as a pension regulatory liability in OG&E's Oklahoma jurisdiction resulting from OG&E's 2009 Oklahoma rate case;
- An increase of $9.7 million in allocations from the holding company primarily due to higher contract professional services expense, materials and supplies expense and communication and media services expense;
- An increase of $9.1 million in other marketing and sales expense related to demand-side management initiatives, which expenses are being recovered through a rider;
- An increase of $7.5 million in salaries and wages expense primarily due to salary increases in 2010;
- An increase of $4.8 million due to increased spending on vegetation management related to system hardening, which expenses are being recovered through a rider;
- An increase of $3.4 million in injuries and damages expense primarily due to increased reserves on claims in 2010;
- An increase of $2.1 million in overtime expense due to the storms in January and May 2010; and
- An increase of $1.7 million in temporary labor expense.

These increases in other operation and maintenance expenses were partially offset by a decrease of $3.9 million in incentive compensation expense primarily due to lower accruals in 2010.

Depreciation and amortization expense was $208.7 million in 2010 as compared to $187.7 million in 2009, an increase of $21.0 million, or 11.2 percent, primarily due to additional assets being placed in service, including OU Spirit that was placed in service in November and December 2009 and Windspeed that was placed in service on March 31, 2010.

Additional Information

Allowance for Equity Funds Used During Construction. Allowance for equity funds used during construction was $11.4 million in 2010 as compared to $15.1 million in 2009, a decrease of $3.7 million, or 24.5 percent, primarily due to the completion of OU Spirit in November and December 2009 and Windspeed on March 31, 2010.

Other Income. Other income was $6.5 million in 2010 as compared to $20.4 million in 2009, a decrease of $13.9 million, or 68.1 percent. The decrease in other income was primarily due to:

- A decrease of $10.0 million due to a decreased level of gains recognized in the guaranteed flat bill program in 2010 from higher than expected usage resulting from warmer weather in addition to more customers participating in the guaranteed flat bill program in 2010; and
- A decrease of $2.6 million related to the benefit associated with the tax gross-up of allowance for equity funds used during construction.

Other Expense. Other expense was $1.6 million in 2010 as compared to $6.7 million in 2009, a decrease of $5.1 million or 76.1 percent, primarily due to a decrease in charitable contributions in 2010 as the holding company made the charitable contributions in 2010.

Interest Expense. Interest expense was $103.4 million in 2010 as compared to $93.6 million in 2009, an increase of $9.8 million, or 10.5 percent. The increase in interest expense was primarily due to:

- An $8.2 million increase related to the issuance of $250 million of long-term debt in June 2010; and
- A $2.8 million increase due to a lower allowance for borrowed funds used during construction in 2010 as compared to 2009.

Income Tax Expense. Income tax expense was $111.0 million in 2010 as compared to $90.0 million in 2009, an increase of $21.0 million, or 23.3 percent, primarily due to:

- Higher pre-tax income in 2010 as compared to 2009;
- An adjustment for the elimination of the tax deduction for the Medicare Part D subsidy; and
- The write-off of previously recognized Oklahoma investment tax credits primarily due to expenditures no longer eligible for the Oklahoma investment tax credit related to the change in the tax method of accounting for capitalization of repair expenditures.

These increases in income tax expense were partially offset by an increase in Federal renewable energy credits in 2010 as compared to 2009.

Enogex (Natural Gas Midstream Operations)

(In millions, year ended December 31)	Transportation and Storage	Gathering and Processing	Marketing	Eliminations	Total
2011					
Operating revenues	**$410.5**	**$1,167.1**	**$678.0**	**$(468.5)**	**$1,787.1**
Cost of goods sold	**253.3**	**870.7**	**688.1**	**(465.5)**	**1,346.6**
Gross margin on revenues	**157.2**	**296.4**	**(10.1)**	**(3.0)**	**440.5**
Other operation and maintenance	**46.5**	**111.8**	**7.3**	**(3.1)**	**162.5**
Depreciation and amortization	**21.6**	**55.6**	**0.4**	**–**	**77.6**
Impairment of assets	**–**	**6.3**	**–**	**–**	**6.3**
Gain on insurance proceeds	**–**	**(3.0)**	**–**	**–**	**(3.0)**
Taxes other than income	**14.7**	**7.0**	**0.3**	**0.1**	**22.1**
Operating income (loss)	**$ 74.4**	**$ 118.7**	**$ (18.1)**	**$ –**	**$ 175.0**
2010					
Operating revenues	$403.6	$1,005.6	$798.5	$(500.0)	$1,707.7
Cost of goods sold	246.4	733.3	804.7	(499.3)	1,285.1
Gross margin on revenues	157.2	272.3	(6.2)	(0.7)	422.6
Other operation and maintenance	48.9	91.5	8.4	(3.5)	145.3
Depreciation and amortization	21.1	50.1	0.1	–	71.3
Impairment of assets	0.7	0.4	–	–	1.1
Taxes other than income	13.9	6.4	0.3	–	20.6
Operating income (loss)	$ 72.6	$ 123.9	$ (15.0)	$ 2.8	$ 184.3
2009					
Operating revenues	$401.0	$ 657.5	$619.9	$(473.3)	$1,205.1
Cost of goods sold	239.9	458.8	617.7	(468.9)	847.5
Gross margin on revenues	161.1	198.7	2.2	(4.4)	357.6
Other operation and maintenance	40.9	87.2	9.2	(4.7)	132.6
Depreciation and amortization	20.4	43.9	0.1	–	64.4
Impairment of assets	0.9	1.9	–	–	2.8
Taxes other than income	13.2	5.5	0.4	–	19.1
Operating income (loss)	$ 85.7	$ 60.2	$ (7.5)	$ 0.3	$ 138.7

Operating Data

Year Ended December 31	2011	2010	2009
Gathered volumes (TBtu/d)(A)	**1.36**	1.32	1.25
Incremental transportation volumes (TBtu/d)(B)	**0.58**	0.40	0.54
Total throughput volumes (TBtu/d)	**1.94**	1.72	1.79
Natural gas processed (TBtu/d)	**0.79**	0.82	0.70
NGLs sold – keep-whole (million gallons)	**167**	187	110
NGLs sold – purchased for resale (million gallons)	**487**	470	351
NGLs sold – percent of liquids (million gallons)	**25**	26	27
NGLs sold – percent of proceeds (million gallons)	**6**	5	5
Total NGLs sold (million gallons)	**685**	688	493
Average NGLs sales price per gallon	**$1.16**	$0.96	$0.77
Average natural gas sales price per MMBtu	**$4.08**	$4.24	$3.37

(A) *Trillion British thermal units per day.*
(B) *Incremental transportation volumes consist of natural gas moved only on the transportation pipeline.*

2011 Compared to 2010

Enogex's operating income decreased $9.3 million, or 5.0 percent, in 2011 as compared to 2010. This decrease was primarily due to higher other operation and maintenance expense, higher depreciation and amortization expense, lower average natural gas prices and a slight decrease in inlet processing volumes related to the 120 MMcf/d Cox City natural gas processing plant being out of service due to the fire from December 2010 until September 2011 and the sale of the Harrah processing plant and the associated Wellston and Davenport gathering assets in April 2011. These decreases were partially offset by higher NGLs prices and increased gathered volumes associated with ongoing expansion projects. In the normal course of Enogex's business, the operation of its gathering, processing and transportation assets results in the creation of physical natural gas long/short positions. These physical positions can result from gas imbalances, actual versus contractual settlement differences, fuel tracker obligations and natural gas received in-kind for compensation or reimbursements. Enogex actively manages its monthly net position through either selling excess gas or purchasing additional gas needs from third parties through OER. In 2011, volume changes and realized margin on physical gas long/short positions decreased the gross margin by $14.8 million, net of corresponding imbalance and fuel tracker obligations and the impact of the recovery of prior years' under-recovered fuel positions during 2010.

Other operation and maintenance expense increased $17.2 million, or 11.8 percent, primarily due to:

- Increased payroll and benefits costs due to increased headcount to support business growth;
- Increased contract technical and professional services expense and materials and supplies expense due to an increase in non-capital projects in 2011;
- Increased property insurance costs;
- Increased rental expense due to growing demand for compression as Enogex's business expands; and
- Increased costs due to soil remediation projects.

Depreciation and amortization expense increased $6.3 million, or 8.8 percent, primarily due to additional assets placed in service throughout 2010 and 2011.

Impairment of assets increased $5.2 million in 2011 primarily due to an impairment of $5.0 million related to the leased Atoka Midstream LLC joint venture ("Atoka") processing plant as a result of a management decision in August 2011 to use third-party processing exclusively for gathered volumes dedicated to Atoka and, therefore, to take the processing plant out of service and return it to the lessor in accordance with the rental agreement. The noncontrolling interest portion of the impairment was $2.5 million which is included in Net Income Attributable to Noncontrolling Interests in the Company's Consolidated Statement of Income.

Gain on insurance proceeds was $3.0 million in 2011 with no comparable item in 2010. The gain on insurance proceeds was for reimbursement related to the damaged train at the Cox City natural gas processing plant being replaced and the facility being returned to full service in September 2011.

Transportation and Storage

The transportation and storage business contributed $157.2 million of Enogex's consolidated gross margin in each of 2011 and 2010. The transportation operations contributed $125.9 million of Enogex's consolidated gross margin in 2011 as compared to $124.3 million in 2010. The storage operations contributed $31.3 million of Enogex's consolidated gross margin in 2011 as compared to $32.9 million in 2010. Factors affecting the transportation and storage gross margin were:

- Higher capacity lease services under the Midcontinent Express Pipeline, LLC ("MEP") and Gulf Crossing capacity leases in 2011 as a result of pipeline integrity work on an Enogex pipeline in 2010, which increased the gross margin by $7.1 million;
- Higher firm 311 services due to new contracts with more favorable rates in 2011, which increased the gross margin by $5.4 million;
- Higher interruptible transportation fees due to new contracts with more favorable rates in 2011, which increased the gross margin by $1.6 million;
- Higher crosshaul revenues in 2011 resulting from the reversal of a previously recognized reserve of $3.0 million associated with the settlement of Enogex's 2009 FERC Section 311 rate case partially offset by decreased utilization of $2.5 million in 2011 due to shippers utilizing crosshaul service in 2010 as a result of pipeline integrity work, which increased the 2011 gross margin by $0.5 million; and
- Lower volumes and realized margin on sales of physical natural gas long positions associated with transportation operations in 2011. Gross margin in 2011 included the under recovery of fuel positions as compared to 2010 that included the recovery of prior year's under-recovered fuel positions, which reduced the gross margin in 2011 by $12.1 million, net of imbalance and fuel tracker obligations.

Other operation and maintenance expense for the transportation and storage business was $2.4 million, or 4.9 percent, lower in 2011 as compared to 2010 primarily due to decreased contract technical and professional services expense and materials and supplies expense due to a decrease in non-capital projects in 2011 partially offset by an increase in payroll and benefits costs due to increased headcount to support business growth.

Gathering and Processing

The gathering and processing business contributed $296.4 million of Enogex's consolidated gross margin in 2011 as compared to $272.3 million in 2010, an increase of $24.1 million, or 8.9 percent. The gathering operations contributed $125.2 million of Enogex's consolidated gross margin in 2011 as compared to $117.6 million in 2010. The processing operations contributed $171.2 million of Enogex's consolidated gross margin in 2011 as compared to $154.7 million in 2010.

In 2011, Enogex realized a higher gross margin in its gathering and processing operations primarily as the result of continued growth in gathered volumes from ongoing expansion projects, primarily in the Granite Wash play and Cana/Woodford Shale play, which has added richer natural gas to Enogex's system and higher NGLs prices. Although gathered volumes increased over 2010, gathering and processing volumes grew at a slower pace during the fourth quarter of 2011 than Enogex had anticipated. Enogex currently expects that this slower growth will continue during 2012. The increased gathering volumes were partially offset by the contract conversion of one of Enogex's five largest customer's Oklahoma production volumes to fixed fee effective July 1, 2011, a slight decrease in inlet processing volumes related to the 120 MMcf/d Cox City natural gas processing plant being out of service due to the fire from December 2010 until September 2011, the sale of the Harrah processing plant and the associated Wellston and Davenport gathering assets in April 2011 and lower average natural gas prices. Overall, the above factors resulted in an increased gross margin on keep-whole processing of $4.8 million and on percent-of-liquids and percent-of-proceeds contracts of $2.6 million.

Other factors that contributed to the increase in the gathering and processing gross margin were:

- An increase in condensate revenues associated with higher condensate prices and volumes, which increased the gross margin by $11.1 million; and
- An increase in gathering fees associated with ongoing expansion projects, which increased the gross margin by $10.7 million.

These increases in the gathering and processing gross margin were partially offset by:

- An increase in the utilization of third-party processing as a result of the reduced capacity related to the Cox City processing plant being out of service until September 2011 and the Atoka processing plant being taken out of service in August 2011, which decreased the gross margin by $3.4 million; and
- Lower volumes and realized margin on sales of physical natural gas long positions associated with gathering operations, which decreased the gross margin in 2011 by $2.7 million, net of imbalance and fuel tracker obligations.

Other operation and maintenance expense for the gathering and processing business was $20.3 million, or 22.2 percent, higher in 2011 as compared to 2010 primarily due to:

- Increased payroll and benefits costs due to increased headcount to support business growth;
- Increased contract technical and professional services expense and materials and supplies expense due to an increase in non-capital projects in 2011;
- Increased rental expense due to growing demand for compression as Enogex's business expands; and
- Increased costs due to soil remediation projects.

Marketing

The marketing business recognized a loss of $10.1 million as part of Enogex's consolidated gross margin in 2011 as compared to a loss of $6.2 million in 2010, a decrease in the gross margin of $3.9 million, primarily due to:

- Lower of cost or market adjustments on the natural gas storage inventory reflective of higher inventory volumes in 2011, which decreased the gross margin by $3.6 million; and
- Lower realized margin on sale of natural gas inventory from storage due to a reduction in the realized natural gas market spreads, which decreased the gross margin by $2.8 million.

These decreases are partially offset by more favorable results from OER's customer-focused risk management services, natural gas marketing activities and its trading activities and the expiration of an unfavorable transportation contract, which increased the gross margin by $2.2 million.

Enogex Consolidated Information

Other Income. Enogex's consolidated other income was $3.9 million in 2011 as compared to $0.2 million in 2010, an increase of $3.7 million, primarily due to the recognition of a gain related to the sale of the Harrah processing plant and the associated Wellston and Davenport gathering assets in April 2011.

Interest Expense. Enogex's consolidated interest expense was $22.9 million in 2011 as compared to $30.4 million in 2010, a decrease of $7.5 million, or 24.7 percent, primarily due to:

- An increase of $6.1 million in capitalized interest related to increased construction activity in 2011; and
- A decrease of $1.0 million in interest expense in 2011 due to the retirement of long-term debt in January 2010.

Income Tax Expense. Enogex's consolidated income tax expense was $51.7 million in 2011 as compared to $57.7 million in 2010, a decrease of $6.0 million, or 10.4 percent, primarily due to:

- Lower pre-tax income in 2011 as compared to 2010; and
- The one-time, non-cash charge in 2010 for the elimination of the tax deduction for the Medicare Part D subsidy.

Noncontrolling Interest. Enogex's net income attributable to noncontrolling interest was $20.8 million in 2011 as compared to $5.1 million in 2010, an increase of $15.7 million, due to the equity sale of a membership interest in Enogex Holdings to the ArcLight group partially offset by an impairment recorded in August 2011 related to the Atoka processing plant.

Non-Recurring Item. In 2011, Enogex had an increase in net income of $2.3 million relating to the sale of the Harrah processing plant and the associated Wellston and Davenport gathering assets in April 2011, which Enogex does not consider to be reflective of its ongoing performance.

Timing Item. Enogex's net income in 2011 was $82.2 million, which included a loss of $2.6 million resulting from recording OER's natural gas storage inventory at the lower of cost or market value. The offsetting gains from the sale of withdrawals from inventory are expected to be realized during the first quarter of 2012.

2010 Compared to 2009

Enogex's operating income increased $45.6 million, or 32.9 percent, in 2010 as compared to 2009. This increase was primarily due to higher processing spreads, higher NGLs prices, higher natural gas prices, increased volumes and higher gallons per million cubic foot of natural gas associated with expansion projects. Additionally, the fourth quarter 2009 addition of the higher efficiency Clinton processing plant enabled Enogex to optimize recoveries across all processing plants. In the normal course of Enogex's business, the operation of its gathering, processing and transportation assets results in the creation of physical natural gas long/short positions. These physical positions can result from gas imbalances, actual versus contractual settlement differences, fuel tracker obligations and natural gas received in-kind for compensation or reimbursements. Enogex actively manages its monthly net position through either selling excess gas or purchasing additional gas needs from third parties through OER.

Other operation and maintenance expense increased $12.7 million, or 9.6 percent, primarily due to salary increases in 2010, increased costs related to pipeline integrity assessments and other non-capital projects and the 2009 reversal of a reserve related to the dismissal of a previously reported natural gas measurement case partially offset by decreased costs associated with the 2010 settlement of the November 2008 pipeline rupture and the recognition of a related insurance reimbursement.

Depreciation and amortization expense increased $5.2 million, or 7.7 percent, primarily due to additional assets placed in service throughout 2009 and 2010.

Taxes other than income increased $1.5 million, or 7.9 percent, primarily due to an increase in ad valorem tax expense as a result of assets placed in service in 2009.

Transportation and Storage

The transportation and storage business contributed $157.2 million of Enogex's consolidated gross margin in 2010 as compared to $161.1 million in 2009, a decrease of $3.9 million, or 2.4 percent. The transportation operations contributed $124.3 million of Enogex's consolidated gross margin in 2010 as compared to $130.3 million in 2009. The storage operations contributed $32.9 million of Enogex's consolidated gross margin in 2010 as compared to $30.8 million in 2009. The transportation and storage gross margin decreased primarily due to:

- Lower revenues resulting from refunds associated with lease services under the MEP and Gulf Crossing capacity leases and the firm 311 services due to pipeline integrity work, which decreased the gross margin by $9.2 million;
- Lower crosshaul volumes as fewer customers moved natural gas to eastern markets in 2010 as there were smaller differences in natural gas prices at various U.S. market locations partially offset by customers utilizing crosshaul services due to pipeline integrity work on an Enogex pipeline, which decreased the gross margin by $5.7 million;
- Lower realized margins on operational storage hedges as the result of lower transacted volumes in 2010 as compared to 2009, which decreased the gross margin by $2.3 million;
- Lower storage fees due to a reduction in the market value of storage capacity, which decreased the gross margin by $2.0 million; and
- Decreased interruptible transportation revenues due to gathering customers shipping production through the firm capacity leases and firm 311 East side service, which decreased the gross margin by $1.6 million.

These decreases in the transportation and storage gross margin were partially offset by:

- Lease services under the MEP and Gulf Crossing capacity leases and firm 311 services due to these services being available beginning in the second quarter 2009, which increased the gross margin by $9.0 million;
- No adjustment of natural gas storage inventory in 2010 as compared to $5.8 million lower of cost or market adjustment to the natural gas storage inventory in 2009 due to lower natural gas prices;
- A decrease in the imbalance liability, net of fuel recoveries and natural gas length positions, which increased the gross margin by $1.2 million; and
- Higher transportation demand fees due to new contracts which began in 2010, which increased the gross margin by $1.1 million.

Other operation and maintenance expense for the transportation and storage business was $8.0 million, or 19.6 percent, higher in 2010 as compared to 2009 primarily due to salary increases in 2010, increased costs of $3.9 million related to pipeline integrity assessments and other non-capital projects and the 2009 reversal of a $1.5 million reserve related to the dismissal of a previously reported natural gas measurement case.

Gathering and Processing

The gathering and processing business contributed $272.3 million of Enogex's consolidated gross margin in 2010 as compared to $198.7 million in 2009, an increase of $73.6 million, or 37.0 percent. The gathering operations contributed $117.6 million of Enogex's consolidated gross margin in 2010 as compared to $114.0 million in 2009. The processing operations contributed $154.7 million of Enogex's consolidated gross margin in 2010 as compared to $84.7 million in 2009.

In 2010, Enogex realized a higher gross margin in its gathering and processing operations primarily as the result of continued growth in gathered volumes, higher processing spreads, higher NGLs prices and higher natural gas prices, net of Enogex's continued effort to convert customers from keep-whole to fixed-fee processing arrangements. Enogex's processing plants saw a 17.0 percent increase in inlet volumes, an increase in NGLs production as recent expansion projects, primarily in the Granite Wash play and Cana/Woodford Shale play have added richer natural gas to Enogex's system and the fourth quarter 2009 completion of the new higher efficiency Clinton processing plant allowed Enogex to optimize recoveries across all processing plants. In December

2010, a fire occurred at Enogex's Cox City natural gas processing plant, and gas volumes normally processed at the Cox City plant were diverted to other facilities by the end of December. Overall, the above factors resulted in the following:

- Increased gross margin on keep-whole processing of $35.8 million;
- Increased fixed processing fees of $13.8 million; and
- Increased gross margin on NGLs retained under percent-of-liquids contracts of $11.4 million.

Other factors that contributed to the increase in the gathering and processing gross margin were:

- An increase in condensate revenues associated with the gathering and processing operations as a result of increased volumes associated with new expansion projects with a higher gallons per million cubic foot of natural gas and higher condensate prices, which increased the gross margin by $11.6 million; and
- Increased gathered volumes associated with expansion projects, which increased the gross margin by $4.3 million.

These increases in the gathering and processing gross margin were partially offset by:

- Lower volumes and realized margin on sales of physical natural gas long/short positions associated with gathering operations, which decreased the gross margin by $1.3 million, net of imbalance and fuel tracker obligations; and
- Increased processing fees associated with the increased utilization of a third-party processing plant for processing natural gas associated with Atoka, which decreased the gross margin by $1.2 million.

Other operation and maintenance expense for the gathering and processing business was $4.3 million, or 4.9 percent, higher in 2010 as compared to 2009 primarily due to an increase of $2.1 million in non-capital project costs partially offset by decreased costs associated with the 2010 settlement of the November 2008 pipeline rupture and the recognition of a related insurance reimbursement.

Marketing

The marketing business recognized a loss of $6.2 million as part of Enogex's consolidated gross margin in 2010 as compared to a gain of $2.2 million in 2009, a decrease of $8.4 million. The marketing gross margin decreased primarily due to:

- Smaller differences in natural gas prices at various U.S. market locations which resulted in a reduced spread that OER was able to realize from delivering gas under its transportation contracts, which decreased the gross margin by $5.5 million;
- Timing of the withdrawal and sale of natural gas inventory from OER's storage contracts, which decreased the gross margin by $1.9 million; and
- Selective deal execution to limit credit and commodity price risks in the current market environment, as well as lack of spreads and volatility in the natural gas commodity markets, resulted in limited opportunities for OER in its customer-focused risk management services and natural gas marketing activities, which decreased the gross margin by $1.0 million.

Enogex Consolidated Information

Interest Expense. Enogex's consolidated interest expense was $30.4 million in 2010 as compared to $36.5 million in 2009, a decrease of $6.1 million, or 16.7 percent, primarily due to:

- A decrease of $7.0 million in interest expense in 2010 as compared to 2009 due to a lower interest rate on long-term debt issued in 2009 as compared to the interest rate on long-term debt that was retired in January 2010; and
- A $2.8 million tender payment on the tender offer Enogex completed in July 2009 related to the retirement of $110.8 million of senior notes.

These decreases in interest expense were partially offset by a decrease of $3.8 million in capitalized interest related to lower capital expenditures and fewer projects qualifying for capitalized interest in 2010 as compared to 2009.

Income Tax Expense. Enogex's consolidated income tax expense was $57.7 million in 2010 as compared to $37.8 million in 2009, an increase of $19.9 million, or 52.6 percent, primarily due to higher pre-tax income in 2010 as compared to 2009 and an adjustment for the elimination of the tax deduction for the Medicare Part D subsidy.

Noncontrolling Interest. Enogex's net income attributable to noncontrolling interest was $5.1 million in 2010 as compared to $2.8 million in 2009, an increase of $2.3 million, or 82.1 percent, due to the equity investment by the ArcLight group in November 2010 in exchange for a 9.9 percent membership interest in Enogex Holdings.

Non-recurring Items. Enogex had net income of $91.1 million in 2010, which did not include any items that Enogex does not consider to be reflective of its ongoing operations. Enogex had net income of $61.3 million in 2009, which includes a net loss of $0.8 million for items Enogex did not consider to be reflective of its ongoing operations. This decrease in Enogex's consolidated net income included a tender payment on the tender offer Enogex completed in July 2009 of $1.7 million after-tax for the purchase of $110.8 million of Enogex's $400 million 8.125% senior notes that matured on January 15, 2010, which was partially offset by the reversal of a reserve of $0.9 million after-tax in 2009 related to the dismissal of a previously reported natural gas measurement case.

Financial Condition

The balance of Accounts Receivable, Net was $322.5 million and $277.9 million at December 31, 2011 and 2010, respectively, an increase of $44.6 million, or 16.0 percent, primarily due to an increase in billings to OG&E's customers in 2011 while customers received a refund in 2010 for the over collection of fuel.

The balance of Fuel Inventories was $100.7 million and $158.8 million at December 31, 2011 and 2010, respectively, a decrease of $58.1 million, or 36.6 percent, primarily due to lower coal inventory balances at OG&E from higher coal generation.

The balance of Property, Plant and Equipment in Service was $10,315.9 million and $9,188.0 million at December 31, 2011 and 2010, respectively, an increase of $1,127.9 million, or 12.3 percent, primarily due to assets placed in service in 2011, including the Crossroads wind farm, distribution and transmission projects and Smart Grid assets at OG&E as well as gathering and processing projects at Enogex.

The balance of Intangible Assets, Net was $137.0 million and $2.8 million at December 31, 2011 and 2010, respectively, an increase of $134.2 million, primarily due to certain gas gathering acquisitions as discussed in Note 3 of Notes to Consolidated Financial Statements.

The balance of Goodwill was $39.4 million at December 31, 2011 with no balance at December 31, 2010 due to certain gas gathering acquisitions as discussed in Note 3 of Notes to Consolidated Financial Statements.

The balance of Short-Term Debt was $277.1 million and $145.0 million at December 31, 2011 and 2010, respectively, an increase of $132.1 million, or 91.1 percent, primarily due to an increase in commercial paper borrowings in 2011 for dividend and bond interest payments, capital expenditures for various transmission projects and Crossroads at OG&E and gathering and processing expansion projects at Enogex and daily operational needs partially offset by proceeds received from contributions from the ArcLight group in 2011 and the equity sale of a 0.1 percent membership interest in Enogex Holdings to the ArcLight group in February 2011, a portion of which were used to repay outstanding commercial paper borrowings.

The balance of Accounts Payable was $388.0 million and $321.7 million at December 31, 2011 and 2010, respectively, an increase of $66.3 million, or 20.6 percent, primarily due to the timing of outstanding checks clearing the bank and an increase in accruals related to Crossroads and Smart Grid projects at OG&E and expansion projects at Enogex.

The balance of Current Price Risk Management Liabilities was $0.4 million and $16.8 million at December 31, 2011 and 2010, respectively, a decrease of $16.4 million or 97.6 percent, primarily due to Enogex hedges of keep-whole processing agreements that matured during 2011.

The balance of Fuel Clause Over Recoveries was $7.7 million and $29.9 million at December 31, 2011 and 2010, respectively, a decrease of $22.2 million, or 74.2 percent, primarily due to the fact that the amount billed to retail customers was lower than OG&E's cost of fuel. OG&E's fuel recovery clauses are designed to smooth the impact of fuel price volatility on customers' bills. As a result, OG&E under recovers fuel costs in periods of rising fuel prices above the baseline charge for fuel and over recovers fuel costs when prices decline below the baseline charge for fuel. Provisions in the fuel clauses are intended to allow OG&E to amortize under and over recovery balances.

The balance of Long-Term Debt was $2,737.1 million and $2,362.9 million at December 31, 2011 and 2010, respectively, an increase of $374.2 million, or 15.8 percent, due to the issuance of $250 million of long-term debt in May 2011 and an increase in borrowings under Enogex LLC's revolving credit agreement.

The balance of Accrued Benefit Obligations was $360.8 million and $372.4 million at December 31, 2011 and 2010, respectively, a decrease of $11.6 million, or 3.1 percent, primarily due to amendments to the Company's retiree medical plan adopted in January 2011 (see Note 14 of Notes to Consolidated Financial Statements) and qualified defined benefit retirement plan ("Pension Plan") contributions in 2011 partially offset by net losses for the Company's Pension Plan, restoration of retirement income plan and postretirement benefit plans.

The balance of Deferred Income Taxes was $1,651.4 million and $1,434.8 million at December 31, 2011 and 2010, respectively, an increase of $216.6 million, or 15.1 percent, primarily due to accelerated bonus tax depreciation partially offset by the Company being in a tax net operating loss position in 2011.

The balance of Regulatory Liabilities was $230.7 million and $193.1 million at December 31, 2011 and 2010, respectively, an increase of $37.6 million, or 19.5 percent, primarily due to increases related to removal obligations for OG&E distribution, transmission and generation assets and Oklahoma pension regulatory liabilities.

The balance of Other Deferred Liabilities was $61.2 million and $45.3 million at December 31, 2011 and 2010, respectively, an increase of $15.9 million, or 35.1 percent, primarily due to an asset retirement obligation related to the Crossroads wind farm.

The balance of Accumulated Other Comprehensive Loss was $40.6 million and $60.2 million at December 31, 2011 and 2010, respectively, a decrease of $19.6 million, or 32.6 percent, primarily due to amendments to the Company's retiree medical plan adopted in January 2011 (see Note 14 of Notes to Consolidated Financial Statements) and NGLs hedges maturing in 2011 partially offset by net losses for the Pension Plan, restoration of retirement income plan and postretirement benefit plans.

The balance of Noncontrolling Interests was $256.0 million and $110.4 million at December 31, 2011 and 2010, respectively, an increase of $145.6 million, primarily due to contributions from the ArcLight group in 2011 and the equity sale of a 0.1 percent membership interest in Enogex Holdings to the ArcLight group in February 2011 partially offset by distributions to the ArcLight group in 2011.

Off-Balance Sheet Arrangement

OG&E Railcar Lease Agreement

OG&E has a noncancellable operating lease with purchase options, covering 1,392 coal hopper railcars to transport coal from Wyoming to OG&E's coal-fired generation units. Rental payments are charged to Fuel Expense and are recovered through OG&E's tariffs and fuel adjustment clauses. On December 15, 2010, OG&E renewed the lease agreement effective February 1, 2011. At the end of the new lease term, which is February 1, 2016, OG&E has the option to either purchase the railcars at a stipulated fair market value or renew the lease. If OG&E chooses not to purchase the railcars or renew the lease agreement and the actual fair value of the railcars is less than the stipulated fair market value, OG&E would be responsible for the difference in those values up to a maximum of $22.8 million.

OG&E is also required to maintain all of the railcars it has under lease to transport coal from Wyoming and has entered into agreements with Progress Rail Services and WATCO, both of which are non-affiliated companies, to furnish this maintenance.

Liquidity and Capital Resources

Cash Flows

(In millions, year ended December 31)	2011	2010	2009
Net cash provided from operating activities	**$ 833.9**	$ 782.5	$ 654.5
Net cash used in investing activities	**(1,395.8)**	(846.1)	(808.5)
Net cash provided from financing activities	**564.2**	7.8	37.7

Operating Activities

The increase of $51.4 million, or 6.6 percent, in net cash provided from operating activities in 2011 as compared to 2010 was primarily due to lower fuel refunds at OG&E in 2011 as compared to 2010 and cash received in 2011 from an increase in billings to OG&E's customers due to warmer weather in OG&E's service territory in 2011 partially offset by income tax refunds received in 2010 related to a carry back of the 2008 tax loss resulting from a change in tax method of accounting for capitalization of repair expenditures and accelerated tax bonus depreciation.

The increase of $128.0 million, or 19.6 percent, in net cash provided from operating activities in 2010 as compared to 2009 was primarily due to:

- An increase in cash receipts for sales at Enogex due to an increase in natural gas prices and NGLs prices and volumes in 2010 as compared to 2009;
- Income tax refunds received in 2010 related to a carry back of the 2008 tax loss resulting from a change in tax method of accounting for capitalization of repair expenditures and accelerated tax bonus depreciation;
- A cash collateral payment to counterparties of OER related to OER's NGLs hedge positions in 2009; and
- Cash received in 2010 from the implementation of rate increases and riders at OG&E.

These increases in net cash provided from operating activities were partially offset by:

- An increase in payments for purchases at Enogex due to an increase in natural gas prices and NGLs prices and volumes in 2010 as compared to 2009; and
- Higher fuel refunds at OG&E in 2010 as compared to 2009.

Investing Activities

The increase of $549.7 million, or 65.0 percent, in net cash used in investing activities in 2011 as compared to 2010 primarily related to higher levels of capital expenditures in 2011 related to various transmission projects and Crossroads at OG&E and gathering and processing expansion projects at Enogex.

The increase of $37.6 million, or 4.7 percent, in net cash used in investing activities in 2010 as compared to 2009 primarily related to a customer's reimbursement of Enogex's costs related to the ongoing construction of a transportation pipeline in 2009.

Financing Activities

The increase of $556.4 million in net cash provided from financing activities in 2011 as compared to 2010 was primarily due to:

- Repayment in 2010 of the remaining balance of Enogex LLC's $400 million 8.125% senior notes which matured on January 15, 2010;
- An increase in short-term debt borrowings in 2011 as compared to 2010;
- Contributions from the noncontrolling interest partners in 2011;
- Higher borrowings under Enogex LLC's revolving credit agreement in 2011; and
- A decrease in repayments of borrowings under Enogex LLC's revolving credit agreement in 2011 as compared to 2010.

The decrease of $29.9 million, or 79.3 percent, in net cash provided from financing activities in 2010 as compared to 2009 was primarily due to:

- Repayment of the remaining balance of Enogex LLC's $400 million 8.125% senior notes which matured on January 15, 2010 partially offset by the retirement of $110.8 million of senior notes related to the tender offer Enogex completed in July 2009;
- Proceeds received from the issuance of $450 million of long-term debt at Enogex LLC in June 2009; and
- A decrease in the issuance of common stock in 2010.

These decreases in net cash provided from financing activities were partially offset by:

- Proceeds received from the issuance of $250 million of long-term debt at OG&E in June 2010;
- Proceeds received from the ArcLight group for the equity investment in Enogex Holdings in November 2010;
- Lower repayments of short-term debt borrowings in 2010;
- A higher level of proceeds received from borrowings on Enogex LLC's line of credit in 2010; and
- A higher level of repayments made on Enogex LLC's line of credit in 2009.

Future Capital Requirements and Financing Activities

The Company's primary needs for capital are related to acquiring or constructing new facilities and replacing or expanding existing facilities at OG&E and Enogex. Other working capital requirements are expected to be primarily related to maturing debt, operating lease obligations, hedging activities, fuel clause under and over recoveries and other general corporate purposes. The Company generally meets its cash needs through a combination of cash generated from operations, short-term borrowings (through a combination of bank borrowings and commercial paper) and permanent financings.

Capital Expenditures

The Company's consolidated estimates of capital expenditures for the years 2012 through 2016 are shown in the following table. These capital expenditures represent the base maintenance capital expenditures (i.e., capital expenditures to maintain and operate the Company's businesses) plus capital expenditures for known and committed projects.

Additional capital expenditures beyond those identified in the table below, including additional incremental growth opportunities in electric transmission assets and at Enogex LLC, will be evaluated based upon their impact upon achieving the Company's financial objectives. The capital expenditure projections related to Enogex LLC in the table below reflect base market conditions at February 16, 2012 and do not reflect the potential opportunity for a set of growth projects that could materialize. Also, if drilling activity declines in the future, this could reduce Enogex's capital expenditures in the table below.

(In millions)	2012	2013	2014	2015	2016
OG&E base transmission	$ 80	$ 50	$ 50	$ 50	$ 50
OG&E base distribution	195	200	200	200	200
OG&E base generation	110	80	80	80	80
OG&E other	30	30	30	30	30
Total OG&E base transmission, distribution, generation and other	415	360	360	360	360
OG&E known and committed projects:					
Transmission projects:					
Sunnyside-Hugo (345 kilovolt)	25	–	–	–	–
Sooner-Rose Hill (345 kilovolt)	5	–	–	–	–
Balanced Portfolio 3E Projects	110	180	50	–	–
SPP Priority Projects	20	200	115	–	–
Total transmission projects	160	380	165	–	–
Other projects:					
Smart Grid Program (A)	90	35	40	20	20
Crossroads	40	–	–	–	–
System Hardening	15	–	–	–	–
Total other projects	145	35	40	20	20
Total OG&E known and committed projects	305	415	205	20	20
Total OG&E (B)	720	775	565	380	380
Enogex LLC base maintenance	60	50	55	60	65
Enogex LLC known and committed projects:					
Western Oklahoma/Texas Panhandle gathering expansion	215	115	15	5	5
Other gathering expansion	25	25	20	20	20
Total Enogex LLC known and committed projects	240	140	35	25	25
Total Enogex LLC (C)	300	190	90	85	90
OGE Energy	20	20	20	20	20
Total capital expenditures	$1,040	$985	$675	$485	$490

(A) *These capital expenditures are net of the $130 million Smart Grid grant approved by the U.S. Department of Energy.*

(B) *The capital expenditures above exclude any environmental expenditures associated with pollution control equipment related to regional haze requirements due to the uncertainty regarding the timing and costs for such pollution control equipment. OG&E has committed to install low nitrogen oxide ("NOX") burners at the affected generating units at a cost preliminarily estimated between $70 million and $130 million, but the timing of the installation of such burners is uncertain. The sulfur dioxide ("SO2") emissions standards in the EPA's Federal implementation plan could require the installation of dry flue gas desulfurization units with spray dryer absorber ("Dry Scrubbers") or fuel switching. OG&E estimates that installing such Dry Scrubbers could cost more than $1.0 billion. The Federal implementation plan is being challenged by OG&E and the state of Oklahoma. Neither the outcome of the challenge to the Federal implementation plan nor the timing and amount of any required capital expenditures can be predicted with any certainty at this time, but such capital expenditures could be significant. For further information, see "Management's Discussion and Analysis of Financial Condition and Results of Operations – Environmental Laws and Regulations" below.*

(C) *These capital expenditures represent 100 percent of Enogex LLC's capital expenditures, of which a portion may be funded by the ArcLight group. Until the ArcLight group owns 50 percent of the equity of Enogex Holdings, the ArcLight group will fund capital contributions in an amount higher than its proportionate interest. If necessary, the ArcLight group will fund between 50 percent and 90 percent of required capital contributions during that period. The remainder of the required capital contributions (i.e., between 10 percent and 50 percent) will be funded by OGE Holdings.*

Contractual Obligations

The following table summarizes the Company's contractual obligations at December 31, 2011. See the Company's Consolidated Statements of Capitalization and Note 16 of Notes to Consolidated Financial Statements for additional information.

(In millions)	2012	2013–2014	2015–2016	After 2016	Total
Maturities of long-term debt[(A)]	$ –	$ 300.0	$ 260.0	$ 2,185.4	$ 2,745.4
Operating lease obligations					
OG&E railcars	2.9	5.7	30.1	–	38.7
Enogex noncancellable operating leases	3.9	5.4	4.6	0.6	14.5
Total operating lease obligations	6.8	11.1	34.7	0.6	53.2
Other purchase obligations and commitments					
OG&E cogeneration capacity and fixed operation and maintenance payments	90.3	176.7	168.5	401.1	836.6
OG&E expected cogeneration energy payments	59.3	150.2	161.0	600.8	971.3
OG&E minimum fuel purchase commitments	380.2	280.3	90.4	–	750.9
OG&E expected wind purchase commitments	32.4	66.1	68.7	492.0	659.2
OG&E long-term service agreements	4.5	40.3	10.1	59.8	114.7
OER Cheyenne Plains commitments	5.3	13.0	1.6	–	19.9
OER MEP commitments	2.1	3.3	–	–	5.4
OER other commitments	4.9	6.2	3.8	–	14.9
Total other purchase obligations and commitments	579.0	736.1	504.1	1,553.7	3,372.9
Total contractual obligations	585.8	1,047.2	798.8	3,739.7	6,171.5
Amounts recoverable through fuel adjustment clause[(B)]	(474.8)	(502.3)	(350.2)	(1,092.8)	(2,420.1)
Total contractual obligations, net	$ 111.0	$ 544.9	$ 448.6	$ 2,646.9	$ 3,751.4

[(A)] *Maturities of the Company's long-term debt during the next five years consist of $300 million and $260 million in years 2014 and 2016, respectively. There are no maturities of the Company's long-term debt in years 2012, 2013 or 2015.*

[(B)] *Includes expected recoveries of costs incurred for OG&E's railcar operating lease obligations, OG&E's cogeneration expected energy payments, OG&E's minimum fuel purchase commitments and OG&E's expected wind purchase commitments.*

OG&E also has 720 MWs of qualified cogeneration facilities ("QF") contracts to meet its current and future expected customer needs. OG&E will continue reviewing all of the supply alternatives to these contracts with QFs and small power production producers ("QF contracts") that minimize the total cost of generation to its customers, including exercising its options (if applicable) to extend these QF contracts at pre-determined rates.

Variances in the actual cost of fuel used in electric generation (which includes the operating lease obligations for OG&E's railcar leases shown above) and certain purchased power costs, as compared to the fuel component included in the cost-of-service for ratemaking, are passed through to OG&E's customers through fuel adjustment clauses. Accordingly, while the cost of fuel related to operating leases and the vast majority of minimum fuel purchase commitments of OG&E noted above may increase capital requirements, such costs are recoverable through fuel adjustment clauses and have little, if any, impact on net capital requirements and future contractual obligations. The fuel adjustment clauses are subject to periodic review by the OCC, the APSC and the FERC.

Pension and Postretirement Benefit Plans

At December 31, 2011, 38.6 percent of the Pension Plan investments were in listed common stocks with the balance primarily invested in bonds, debentures and notes, U.S. Government securities, a commingled fund and a common collective trust as presented in Note 14 of Notes to Consolidated Financial Statements. In 2011, asset returns on the Pension Plan were 1.4 percent due to the gains in fixed income investments partially offset by losses in equity investments in 2011. During the same time, corporate bond yields, which are used in determining the discount rate for future pension obligations, have continued to decline. During each of 2011 and 2010, OGE Energy made contributions to its Pension Plan of $50 million to help ensure that the Pension Plan maintains an adequate funded status. The level of funding is dependent on returns on plan assets and future discount rates. During 2012, OGE Energy may contribute up to $35 million to its Pension Plan. OGE Energy could be required to make additional contributions if the value of its pension trust and postretirement benefit plan trust assets are adversely impacted by a major market disruption in the future.

The following table presents the status of the Company's Pension Plan, the Restoration of Retirement Income Plan and the postretirement benefit plans at December 31, 2011 and 2010. These amounts have been recorded in Accrued Benefit Obligations with the offset in Accumulated Other Comprehensive Loss (except OG&E's portion which is recorded as a regulatory asset as discussed in Note 1 of Notes to Consolidated Financial Statements) in the Company's Consolidated Balance Sheet.

The amounts in Accumulated Other Comprehensive Loss and those recorded as a regulatory asset represent a net periodic benefit cost to be recognized in the Consolidated Statements of Income in future periods.

	Pension Plan		Restoration of Retirement Income Plan		Postretirement Benefit Plans	
(In millions, year ended December 31)	**2011**	2010	**2011**	2010	**2011**	2010
Benefit obligations	**$(697.7)**	$(640.9)	**$(13.3)**	$(10.8)	**$(280.6)**	$(337.1)
Fair value of plan assets	**589.8**	574.0	**–**	–	**61.0**	58.5
Funded status at end of year	**$(107.9)**	$ (66.9)	**$(13.3)**	$(10.8)	**$(219.6)**	$(278.6)

Common Stock Dividends

The Company's dividend policy is reviewed by the Board of Directors at least annually and is based on numerous factors, including management's estimation of the long-term earnings power of its businesses. The Company's financial objective includes increasing the dividend to meet the Company's dividend payout objectives. The Company's target payout ratio is to pay out dividends no more than 60 percent of its normalized earnings on an annual basis. The target payout ratio has been determined after consideration of numerous factors, including the largely retail composition of the Company's shareholder base, the Company's financial position, the Company's growth targets, the composition of the Company's assets and investment opportunities. At the Company's December 2011 Board meeting, management, after considering estimates of future earnings and numerous other factors, recommended to the Board of Directors an increase in the current quarterly dividend rate to $0.3925 per share from $0.3750 per share effective with the Company's first quarter 2012 dividend.

Security Ratings

	Moody's Investor Services	Standard & Poor's Ratings Services	Fitch Ratings
OG&E senior notes	A2	BBB+	A+
Enogex LLC notes	Baa3	BBB-	BBB
OGE Energy senior notes	Baa1	BBB	A
OGE Energy commercial paper	P2	A2	F1

Access to reasonably priced capital is dependent in part on credit and security ratings. Generally, lower ratings lead to higher financing costs. Pricing grids associated with the Company's credit facilities could cause annual fees and borrowing rates to increase if an adverse ratings impact occurs. The impact of any future downgrade could include an increase in the costs of the Company's short-term borrowings, but a reduction in the Company's credit ratings would not result in any defaults or accelerations. Any future downgrade of the Company could also lead to higher long-term borrowing costs and, if below investment grade, would require the Company to post cash collateral or letters of credit. In the event Moody's Investors Services or Standard & Poor's Ratings Services were to lower the Company's senior unsecured debt rating to a below investment grade rating, at December 31, 2011, the Company would have been required to post $2.1 million of cash collateral to satisfy its obligation under its financial and physical contracts relating to derivative instruments that are in a net liability position at December 31, 2011. In addition, the Company could be required to provide additional credit assurances in future dealings with third parties, which could include letters of credit or cash collateral.

On October 25, 2011, Standard & Poor's Ratings Services reaffirmed the security ratings of OGE Energy and OG&E as shown in the table below and downgraded Enogex LLC's security rating from BBB+ to BBB- with a stable outlook. Standard & Poor's Ratings Services indicated that the downgrade at Enogex LLC was primarily due to OGE Energy's lower ownership percentage in Enogex which according to Standard & Poor's Ratings Services, over time, lessens the benefit that Enogex receives from OGE Energy's higher credit rating. The downgrade did not trigger any collateral requirements and will not cause a material increase in fees under the revolving credit agreement.

A security rating is not a recommendation to buy, sell or hold securities. Such rating may be subject to revision or withdrawal at any time by the credit rating agency and each rating should be evaluated independently of any other rating.

Future financing requirements may be dependent, to varying degrees, upon numerous factors such as general economic conditions, abnormal weather, load growth, commodity prices, levels of drilling activity, acquisitions of other businesses and/or development of projects, actions by rating agencies, inflation, changes in environmental laws or regulations, rate increases or decreases allowed by regulatory agencies, new legislation and market entry of competing electric power generators.

2011 Capital Requirements, Sources of Financing, Funding of Benefit Plans and Financing Activities

Total capital requirements, consisting of capital expenditures and maturities of long-term debt, were $1,446.2 million and contractual obligations, net of recoveries through fuel adjustment clauses, were $110.2 million resulting in total net capital requirements and contractual obligations of $1,556.4 million in 2011, of which $6.9 million was to comply with environmental regulations. This compares to net capital requirements of $1,111.3 million and net contractual obligations of $104.4 million totaling $1,215.7 million in 2010, of which $27.8 million was to comply with environmental regulations.

In 2011, the Company's sources of capital were cash generated from operations, proceeds from the issuance of long and short-term debt, proceeds from the sales of common stock to the public through the Company's Automatic Dividend Reinvestment and Stock Purchase Plan, funding for growth opportunities at Enogex through the ArcLight group and quarterly distributions from Enogex Holdings. Changes in working capital reflect the seasonal nature of the Company's business, the revenue lag between billing and collection from customers and fuel inventories. See "Financial Condition" for a discussion of significant changes in net working capital requirements as it pertains to operating cash flow and liquidity.

Funding of Benefit Plans

In November 2011, the Company purchased 120,000 shares of its common stock at an average cost of $51.33 per share on the open market. These shares will be used to satisfy Enogex's portion of the Company's obligation to deliver shares of common stock related to long-term incentive payouts of earned performance units in 2012. The Company expects to purchase shares in the future to satisfy a portion of its obligation under its incentive plan.

OG&E Issuance of Long-Term Debt

On May 24, 2011, OG&E issued $250 million of 5.25% senior notes due May 15, 2041. The proceeds from the issuance were added to OGE Energy's general funds and were used to repay short-term debt. OG&E expects to issue additional long-term debt from time to time when market conditions are favorable and when the need arises.

Potential Collateral Requirements

Derivative instruments are utilized in managing the Company's commodity price exposures and in OER's asset management, marketing and trading activities and hedging activities executed on behalf of the Company. Agreements governing the derivative instruments may require the Company to provide collateral in the form of cash or a letter of credit in the event mark-to-market exposures exceed contractual thresholds or the Company's credit ratings are lowered. Future collateral requirements are uncertain, and are subject to terms of the specific agreements and to fluctuations in natural gas and NGLs market prices.

On July 21, 2010, President Obama signed into law Dodd-Frank Wall Street Reform and Consumer Protection Act (the "Dodd-Frank Act"). While the Dodd-Frank Act is focused primarily on the regulation and oversight of financial institutions, it also provides for a new regulatory regime for derivatives, including mandatory clearing of certain swaps, exchange trading, margin requirements and other transparency requirements. The Dodd-Frank Act contains provisions that should exempt certain derivatives end-users from much of the clearing requirements. It is unclear whether end-users will be exempt from the margin requirements. The scope of the margin requirements and the end user exemption is uncertain and will be further defined through rulemaking proceedings at the Commodity Futures Trading Commission and the Securities and Exchange Commission. Further, although the Company may qualify for certain exemptions, its derivative counterparties may be subject to new capital, margin and business conduct requirements imposed as a result of the new legislation, which may increase the Company's transaction costs or make it more difficult to enter into hedging transactions on favorable terms. The Company's inability to enter into hedging transactions on favorable terms, or at all, could increase operating expenses and put the Company at increased exposure to risks of adverse changes in commodities prices. If, as a result of the rulemaking associated with the Dodd-Frank Act, the Company does not qualify for any exemptions related to clearing requirements and/or are subject to margin requirements, the Company would be subject to higher costs and increased collateral requirements. The impact of the provisions of the Dodd-Frank Act on the Company cannot be determined pending issuance of the final implementing regulations.

Future Sources of Financing

Management expects that cash generated from operations, proceeds from the issuance of long and short-term debt and proceeds from the sales of common stock to the public through the Company's Automatic Dividend Reinvestment and Stock Purchase Plan or other offerings will be adequate over the next three years to meet anticipated cash needs and to fund future growth opportunities. Additionally, the Company will have an additional source of funding for growth opportunities at Enogex through the ArcLight group and from quarterly distributions from Enogex Holdings. The Company utilizes short-term borrowings (through a combination of bank borrowings and commercial paper) to satisfy temporary working capital needs and as an interim source of financing capital expenditures until permanent financing is arranged.

Short-Term Debt and Credit Facilities

Short-term borrowings generally are used to meet working capital requirements. The Company borrows on a short-term basis, as necessary, by the issuance of commercial paper and by borrowings under its revolving credit agreements. In December 2011, the Company, OG&E and Enogex LLC each entered into new unsecured five-year revolving credit facilities totaling in the aggregate $1,550 million ($750 million for the Company, $400 million for OG&E and $400 million for Enogex LLC). The short-term debt balance was $277.1 million and $145.0 million at December 31, 2011 and 2010, respectively. The weighted-average interest rate on short-term debt at December 31, 2011 was 0.48 percent. The average balance of short-term debt in 2011 was $210.7 million at a weighted-average interest rate of 0.36 percent. The maximum month-end balance of short-term debt in 2011 was $323.0 million. Enogex had $150.0 million and $25.0 million in outstanding borrowings under its revolving credit agreement at December 31, 2011 and 2010, respectively. As Enogex LLC's credit agreement matures on December 13, 2016, along with its intent in utilizing its credit agreement, borrowings thereunder are classified as long-term debt in the Company's Consolidated

Balance Sheets. At December 31, 2011, the Company had $1,120.7 million of net available liquidity under its revolving credit agreements. OG&E has the necessary regulatory approvals to incur up to $800 million in short-term borrowings at any one time for a two-year period beginning January 1, 2011 and ending December 31, 2012. At December 31, 2011, the Company had $4.6 million in cash and cash equivalents. See Note 13 of Notes to Consolidated Financial Statements for a discussion of the Company's short-term debt activity.

Expected Issuance of Long-Term Debt

OG&E expects to issue approximately $250 million of long-term debt in late 2012, depending on market conditions, to fund capital expenditures, repay short-term borrowings and for general corporate purposes.

Common Stock

The Company expects to issue between $13 million and $15 million of common stock in its Automatic Dividend Reinvestment and Stock Purchase Plan in 2012. See Note 11 of Notes to Consolidated Financial Statements for a discussion of the Company's common stock activity.

Minimum Quarterly Distributions by Enogex Holdings

Pursuant to the Enogex Holdings LLC Agreement, Enogex Holdings will make minimum quarterly distributions equal to the amount of cash required to cover OGE Energy's anticipated tax liabilities plus $12.5 million, to be distributed in proportion to each member's percentage ownership interest.

Critical Accounting Policies and Estimates

The Consolidated Financial Statements and Notes to Consolidated Financial Statements contain information that is pertinent to Management's Discussion and Analysis. In preparing the Consolidated Financial Statements, management is required to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and contingent liabilities at the date of the Consolidated Financial Statements and the reported amounts of revenues and expenses during the reporting period. Changes to these assumptions and estimates could have a material effect on the Company's Consolidated Financial Statements. However, the Company believes it has taken reasonable, but conservative, positions where assumptions and estimates are used in order to minimize the negative financial impact to the Company that could result if actual results vary from the assumptions and estimates. In management's opinion, the areas of the Company where the most significant judgment is exercised for all Company segments includes the valuation of Pension Plan assumptions, impairment estimates of long-lived assets (including intangible assets) and goodwill, income taxes, contingency reserves, asset retirement obligations, fair value and cash flow hedges and the allowance for uncollectible accounts receivable. For the electric utility segment, the most significant judgment is also exercised in the valuation of regulatory assets and liabilities and unbilled revenues. For the natural gas transportation and storage, gathering and processing and marketing segments, the most significant judgment is also exercised in the valuation of operating revenues, natural gas purchases, purchase and sale contracts, assets and depreciable lives of property, plant and equipment and amortization methodologies related to intangible assets. The selection, application and disclosure of the following critical accounting estimates have been discussed with the Company's Audit Committee. The Company discusses its significant accounting policies, including those that do not require management to make difficult, subjective, or complex judgments or estimates, in Note 1 of Notes to Consolidated Financial Statements.

Consolidated (Including all Company Segments)

Pension and Postretirement Benefit Plans

The Company has a Pension Plan that covers substantially all of the Company's employees hired before December 1, 2009. Also, effective December 1, 2009, the Company's Pension Plan is no longer being offered to employees hired on or after December 1, 2009. The Company also has defined benefit postretirement plans that cover substantially all of its employees. Pension and other postretirement plan expenses and liabilities are determined on an actuarial basis and are affected by the market value of plan assets, estimates of the expected return on plan assets, assumed discount rates and the level of funding. Actual changes in the fair market value of plan assets and differences between the actual return on plan assets and the expected return on plan assets could have a material effect on the amount of pension expense ultimately recognized. The pension plan rate assumptions are shown in Note 14 of Notes to Consolidated Financial Statements. The assumed return on plan assets is based on management's expectation of the long-term return on the plan assets portfolio. The discount rate used to compute the present value of plan liabilities is based generally on rates of high-grade corporate bonds with maturities similar to the average period over which benefits will be paid. The level of funding is dependent on returns on plan assets and future discount rates. Higher returns on plan assets and an increase in discount rates will reduce funding requirements to the Pension Plan. The following table indicates the sensitivity of the Pension Plan funded status to these variables.

	Change	Impact on Funded Status
Actual plan asset returns	+/- 5 percent	+/- $29.5 million
Discount rate	+/- 0.25 percent	+/- $20.3 million
Contributions	+/- $10 million	+/- $10 million

Impairment of Long-Lived Assets (Including Intangible Assets) and Goodwill

The Company assesses its long-lived assets, including intangible assets with finite useful lives, for impairment when there is evidence that events or changes in circumstances require an analysis of the recoverability of an asset's carrying amount. Estimates of future cash flows used to test the recoverability of long-lived assets and intangible assets shall include only the future cash flows (cash inflows less associated cash outflows) that are directly associated with and that are expected to arise as a direct result of the use and eventual disposition of the asset. The fair value of these assets is based on third-party evaluations, prices for similar assets, historical data and projected cash flows. An impairment loss is recognized when the sum of the expected future net cash flows is less than the carrying amount of the asset. The amount of any recognized impairment is based on the estimated fair value of the asset subject to impairment compared to the carrying amount of such asset. In 2011, the Company recorded a pre-tax impairment loss of $5.0 million, of which $2.5 million was the noncontrolling interest portion (see Note 5), related to the Atoka processing plant. The Company recorded no other material impairments in 2011, 2010 and 2009.

As a result of the gas gathering acquisitions on November 1, 2011 discussed in Note 3, Enogex recorded goodwill of $39.4 million and intangible assets of $136.3 million. Enogex will assess its goodwill for impairment at least annually as of October 1 and will assess the intangible assets for impairment as discussed above.

Income Taxes

The Company uses the asset and liability method of accounting for income taxes. Under this method, a deferred tax asset or liability is recognized for the estimated future tax effects attributable to temporary differences between the financial statement basis and the tax basis of assets and liabilities as well as tax credit carry forwards and net operating loss carry forwards. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in the period of the change.

The application of income tax law is complex. Laws and regulations in this area are voluminous and often ambiguous. Interpretations and guidance surrounding income tax laws and regulations change over time. Accordingly, it is necessary to make judgments regarding income tax exposure. As a result, changes in these judgments can materially affect amounts the Company recognized in its consolidated financial statements. Tax positions taken by the Company on its income tax returns that are recognized in the financial statements must satisfy a more likely than not recognition threshold, assuming that the position will be examined by taxing authorities with full knowledge of all relevant information.

Commitments and Contingencies

In the normal course of business, the Company is confronted with issues or events that may result in a contingent liability. These generally relate to lawsuits, claims made by third parties, environmental actions or the action of various regulatory agencies. When appropriate, management consults with legal counsel and other appropriate experts to assess the claim. If, in management's opinion, the Company has incurred a probable loss as set forth by accounting principles generally accepted in the United States ("GAAP"), an estimate is made of the loss and the appropriate accounting entries are reflected in the Company's Consolidated Financial Statements.

Except as disclosed otherwise in the Company's Form 10-K, management, after consultation with legal counsel, does not currently anticipate that liabilities arising out of these pending or threatened lawsuits, claims and contingencies will have a material adverse effect on the Company's consolidated financial position, results of operations or cash flows. See Notes 16 and 17 of Notes to Consolidated Financial Statements and Item 3 of Part I in the Company's Form 10-K for a discussion of the Company's commitments and contingencies.

Asset Retirement Obligations

The Company has previously recorded asset retirement obligations that are being amortized over their respective lives ranging from 20 to 99 years. In the fourth quarter of 2011, OG&E recorded an asset retirement obligation for $13.0 million related to its Crossroads wind farm. Beginning December 1, 2011, OG&E began to amortize the value of the related asset retirement obligation asset over the estimated remaining life of 50 years. The Company also has certain asset retirement obligations that have not been recorded because the Company determined that these assets, primarily related to Enogex's processing plants and compression sites and OG&E's power plant sites, have indefinite lives.

Hedging Policies

The Company designates as cash flow hedges derivatives used to manage commodity price risk exposure for Enogex's NGLs volumes and corresponding keep-whole natural gas resulting from its natural gas processing contracts (processing hedges) and natural gas positions resulting from its natural gas gathering and processing, pipeline and storage operations (operational gas hedges). The Company also designates as cash flow hedges certain derivatives used to manage natural gas commodity exposure for certain natural gas storage inventory positions. Hedges are evaluated prior to execution with respect to the impact on the volatility of forecasted earnings and are evaluated at least quarterly after execution for the impact on earnings. Enogex's cash flow hedges at December 31, 2011 mature by the end of the first quarter of 2012.

From time to time, OG&E and Enogex may engage in cash flow and fair value hedge transactions to modify interest rate exposure and not to modify the overall leverage of the debt portfolio.

Electric Utility Segment

Regulatory Assets and Liabilities

OG&E, as a regulated utility, is subject to accounting principles for certain types of rate-regulated activities, which provide that certain actual or anticipated costs that would otherwise be charged to expense can be deferred as regulatory assets, based on the expected recovery from customers in future rates. Likewise, certain actual or anticipated credits that would otherwise reduce expense can be deferred as regulatory liabilities, based on the expected flowback to customers in future rates. Management's expected recovery of deferred costs and flowback of deferred credits generally results from specific decisions by regulators granting such ratemaking treatment.

OG&E records certain actual or anticipated costs and obligations as regulatory assets or liabilities if it is probable, based on regulatory orders or other available evidence, that the cost or obligation will be included in amounts allowable for recovery or refund in future rates. The benefit obligations regulatory asset is comprised of expenses recorded which are probable of future recovery and that have not yet been recognized as components of net periodic benefit cost, including net loss, prior service cost and net transition obligation.

Unbilled Revenues

OG&E reads its customers' meters and sends bills to its customers throughout each month. As a result, there is a significant amount of customers' electricity consumption that has not been billed at the end of each month. Unbilled revenue is presented in Accrued Unbilled Revenues on the Consolidated Balance Sheets and in Operating Revenues on the Consolidated Statements of Income based on estimates of usage and prices during the period. At December 31, 2011, if the estimated usage or price used in the unbilled revenue calculation were to increase or decrease by one percent, this would cause a change in the unbilled revenues recognized of $0.3 million. At December 31, 2011 and 2010, Accrued Unbilled Revenues were $59.3 million and $56.8 million, respectively. The estimates that management uses in this calculation could vary from the actual amounts to be paid by customers.

Allowance for Uncollectible Accounts Receivable

Customer balances are generally written off if not collected within six months after the final billing date. The allowance for uncollectible accounts receivable for OG&E is calculated by multiplying the last six months of electric revenue by the provision rate. The provision rate is based on a 12-month historical average of actual balances written off. To the extent the historical collection rates are not representative of future collections, there could be an effect on the amount of uncollectible expense recognized. Beginning in August 2009 and going forward, there was a change in the provision calculation as a result of the Oklahoma rate case whereby the portion of the uncollectible provision related to fuel is being recovered through the fuel adjustment clause. Due to the extremely hot weather in OG&E's service territory in 2011, OG&E recorded an additional amount of uncollectible expense anticipating higher customer defaults. At December 31, 2011, if the provision rate were to increase or decrease by 10 percent, this would cause a change in the uncollectible expense recognized of $0.2 million. The allowance for uncollectible accounts receivable is a reduction to Accounts Receivable on the Consolidated Balance Sheets and is included in Other Operation and Maintenance Expense on the Consolidated Statements of Income. The allowance for uncollectible accounts receivable was $3.7 million and $1.6 million at December 31, 2011 and 2010, respectively.

Natural Gas Transportation and Storage, Gathering and Processing and Marketing Segments

Operating Revenues

Operating revenues for gathering, processing, transportation, storage and marketing services for Enogex are recorded each month based on the current month's estimated volumes, contracted prices (considering current commodity prices), historical seasonal fluctuations and any known adjustments. The estimates are reversed in the following month and customers are billed on actual volumes and contracted prices. Gas sales are calculated on current-month nominations and contracted prices. Operating revenues associated with the production of NGLs are estimated based on current-month estimated production and contracted prices. These amounts are reversed in the following month and the customers are billed on actual production and contracted prices. Estimated operating revenues are reflected in Accounts Receivable on the Consolidated Balance Sheets and in Operating Revenues on the Consolidated Statements of Income.

Enogex recognizes revenue from natural gas gathering, processing, transportation, storage and marketing services to third parties as services are provided. Revenue associated with NGLs is recognized when the production is sold.

Enogex records deferred revenue when it receives consideration from a third party before achieving certain criteria that must be met for revenue to be recognized in accordance with GAAP. In August 2010, Enogex completed construction of transportation and compression facilities necessary to provide gas delivery service to a new natural gas-fired electric generation facility near Pryor, Oklahoma. Aid in Construction payments of $36.4 million received in excess of construction costs were recognized as Deferred Revenues on the Company's Consolidated Balance Sheet and are being amortized on a straight-line basis of $1.2 million per year over the life of the related firm transportation service agreement under which service commenced in June 2011. Also, in August 2011, Enogex and one of its five largest customers entered into new agreements, effective July 1, 2011, relating to the customer's gathering and processing volumes on the Oklahoma portion of Enogex's system. As a result of this transaction and as part of the new agreements, Enogex recorded $6.4 million in Deferred Revenues on the Company's Consolidated Balance Sheet at December 31, 2011. Processing revenues under the agreements are recognized based on the estimated average fee per MMBtu processed over the life of the agreements. Enogex expects to record additional deferred revenues during 2012.

Enogex, through OER, engages in energy marketing, trading, risk management and hedging activities related to the purchase and sale of natural gas as well as hedging activity related to the sale of natural gas and NGLs on behalf of the Company. Contracts utilized in these activities generally include purchases and sales for physical delivery of natural gas, over-the-counter forward swap and option contracts and exchange traded futures and options. OER's transactions that qualify as derivatives are reflected at fair value with the resulting unrealized gains and losses recorded as price risk management ("PRM") Assets or Liabilities in the Consolidated Balance Sheets, classified as current or long-term based on their anticipated settlement, or against the brokerage deposits in Other Current Assets. The offsetting unrealized gains and losses from changes in the market value of open contracts are included in Operating Revenues in the Consolidated Statements of Income or in Other Comprehensive Income for derivatives designated and qualifying as cash flow hedges. Contracts resulting in delivery of a commodity are included as sales or purchases in the Consolidated Statements of Income as Operating Revenues or Cost of Goods Sold depending on whether the contract relates to the sale or purchase of the commodity.

Natural Gas Purchases

Estimates for gas purchases are based on estimated volumes and contracted purchase prices. Estimated gas purchases are included in Accounts Payable on the Consolidated Balance Sheets and in Cost of Goods Sold on the Consolidated Statements of Income.

Purchase and Sale Contracts

OER utilizes energy purchases and sales for physical delivery of natural gas and financial instruments including over-the-counter forward swap and option contracts and exchange traded futures and options. The majority of these activities qualify as derivatives and are recorded at fair market value. OER's portfolio is marked to estimated fair market value on a daily basis. When available, actual market prices are utilized in determining the value of natural gas and related derivative commodity instruments. For longer-term positions, which are limited to a maximum of 60 months and certain short-term positions for which market prices are not available, models based on forward price curves are utilized. These models incorporate estimates and assumptions as to a variety of factors such as pricing relationships between various energy commodities and geographic location. Actual experience can vary significantly from these estimates and assumptions.

In nearly all cases, independent market prices are obtained and compared to the values used in determining the fair value, and an oversight group outside of the marketing organization monitors all modeling methodologies and assumptions. The recorded value of the energy contracts may change significantly in the future as the market price for the commodity changes, but the value of transactions not designated as cash flow hedges is subject to mark-to-market risk loss limitations provided under the Company's risk policies. Management utilizes models to estimate the fair value of the Company's energy contracts including derivatives that do not have an independent market price. At December 31, 2011, unrealized mark-to-market gains were $2.9 million, none of which were calculated utilizing models. At December 31, 2011, a price movement of one percent for prices verified by independent parties would result in unrealized mark-to-market gains or losses of less than $0.1 million and a price movement of five percent on model-based prices would result in unrealized mark-to-market gains or losses of less than $0.1 million.

Valuation of Assets

The application of business combination and impairment accounting requires Enogex to use significant estimates and assumptions in determining the fair value of assets and liabilities. The acquisition method of accounting for business combinations requires Enogex to estimate the fair value of assets acquired and liabilities assumed to allocate the proper amount of the purchase price consideration between goodwill and the assets that are depreciated and amortized. Enogex records intangible assets separately from goodwill and amortizes intangible assets with finite lives over their estimated useful life as determined by management. Enogex does not amortize goodwill but instead annually assesses goodwill for impairment.

In 2011, Enogex completed an acquisition accounted for as a business combination as discussed in Note 3 of Notes to Consolidated Financial Statements. As part of this acquisition, Enogex engaged the services of a third-party valuation expert to assist it in determining the fair value of the acquired assets and liabilities, including goodwill; however, the ultimate determination of those values is the responsibility of Enogex's management. Enogex bases its estimates on assumptions believed to be reasonable, but which are inherently uncertain. These valuations require the use of management's assumptions, which would not reflect unanticipated events and circumstances that may occur.

Depreciable Lives of Property, Plant and Equipment and Amortization Methodologies Related to Intangible Assets

The computation of depreciation expense requires judgment regarding the estimated useful lives and salvage value of assets at the time the assets are placed in service. As circumstances warrant, useful lives are adjusted when changes in planned use, changes in estimated production lives of affiliated natural gas basins or other factors indicate that a different life would be more appropriate. Such changes could materially impact future depreciation expense. Changes in useful lives that do not result in the impairment of an asset are recognized prospectively. The computation of amortization expense on intangible assets requires judgment regarding the amortization method used. The intangible asset should be amortized over its useful life using a method of amortization that reflects the pattern in which the economic benefits of the intangible asset are consumed.

Natural Gas Inventory

Natural gas inventory is held by Enogex, through its transportation and storage business to provide operational support for its pipeline deliveries and through its marketing business to manage its leased storage capacity. In an effort to mitigate market price exposures, Enogex may enter into contracts or hedging instruments to protect the cash flows associated with its inventory. All natural gas inventory held by Enogex is valued using moving average cost and is recorded at the lower of cost or market. As part of its recurring marketing activity, OER injects and withdraws natural gas into and out of inventory under the terms of its storage capacity contracts. During the years ended December 31, 2011, 2010 and 2009, Enogex recorded write-downs to market value related to natural gas storage inventory of $4.8 million, $0.3 million and $6.1 million, respectively. The amount of Enogex's natural gas inventory was $23.7 million and $23.9 million at December 31, 2011 and 2010, respectively. The cost of gas associated with sales of natural gas storage inventory is presented in Cost of Goods Sold on the Consolidated Statements of Income.

Allowance for Uncollectible Accounts Receivable

The allowance for uncollectible accounts receivable for Enogex is calculated based on outstanding accounts receivable balances over 180 days old. In addition, other outstanding accounts receivable balances less than 180 days old are reserved on a case-by-case basis when Enogex believes the collection of specific amounts owed is unlikely to occur. The allowance for uncollectible accounts receivable is a reduction to Accounts Receivable on the Consolidated Balance Sheets and is included in Other Operation and Maintenance Expense on the Consolidated Statements of Income. The aggregate allowance for uncollectible accounts receivable for Enogex's transportation and storage, gathering and processing and marketing segments was less than $0.1 million and $0.3 million at December 31, 2011 and 2010, respectively.

Accounting Pronouncements

See Note 2 of Notes to Consolidated Financial Statements for a discussion of recently issued accounting pronouncements that are applicable to the Company.

Commitments and Contingencies

Except as disclosed otherwise in the Company's Form 10-K, management, after consultation with legal counsel, does not currently anticipate that liabilities arising out of these pending or threatened lawsuits, claims and contingencies will have a material adverse effect on the Company's consolidated financial position, results of operations or cash flows. See Notes 16 and 17 of Notes to Consolidated Financial Statements and Item 3 of Part I in the Company's Form 10-K for a discussion of the Company's commitments and contingencies.

Environmental Laws and Regulations

The activities of OG&E and Enogex are subject to stringent and complex Federal, state and local laws and regulations governing environmental protection including the discharge of materials into the environment. These laws and regulations can restrict or impact OG&E's and Enogex's business activities in many ways, such as restricting the way it can handle or dispose of their wastes, requiring remedial action to mitigate pollution conditions that may be caused by their operations or that are attributable to former operators, regulating future construction activities to mitigate harm to threatened or endangered species and requiring the installation and operation of pollution control equipment. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, the imposition of remedial requirements and the issuance of orders enjoining future operations. OG&E and Enogex believe that their operations are in substantial compliance with current Federal, state and local environmental standards.

Environmental regulation can increase the cost of planning, design, initial installation and operation of OG&E's or Enogex's facilities. Historically, OG&E's and Enogex's total expenditures for environmental control facilities and for remediation have not been significant in relation to its consolidated financial position or results of operations. The Company believes, however, that it is reasonably likely that the trend in environmental legislation and regulations will continue towards more restrictive standards. Compliance with these standards is expected to increase the cost of conducting business.

OG&E expects that environmental expenditures necessary to comply with the environmental laws and regulations discussed below will qualify as part of a pre-approval plan to handle state and Federally mandated environmental upgrades which will be recoverable in Oklahoma from OG&E's retail customers under House Bill 1910, which was enacted into law in May 2005.

Of the Company's capital expenditures budgeted for 2012, $34.4 million are to comply with environmental laws and regulations, of which $33.7 million and $0.7 million are related to OG&E and Enogex, respectively. Of the Company's capital expenditures budgeted for 2013, $36.0 million are to comply with environmental laws and regulations, of which $35.3 million and $0.7 million are related to OG&E and Enogex, respectively. The Company's management believes that all of its operations are in substantial compliance with current Federal, state and local environmental standards. It is estimated that OG&E's and Enogex's total expenditures for capital, operating, maintenance and other costs associated with environmental quality will be $51.6 million and $6.2 million, respectively, in 2012 as compared to $24.0 million and $6.5 million, respectively, in 2011. Management continues to evaluate its compliance with existing and proposed environmental legislation and regulations and implement appropriate environmental programs in a competitive market.

Air

Federal Clean Air Act Overview

OG&E's and Enogex's operations are subject to the Federal Clean Air Act, as amended, and comparable state laws and regulations. These laws and regulations regulate emissions of air pollutants from various industrial sources, including electric generating units, natural gas processing plants and compressor stations, and also impose various monitoring and reporting requirements. Such laws and regulations may require that OG&E and Enogex obtain pre-approval for the construction or modification of certain projects or facilities expected to produce air emissions or result in the increase of existing air emissions, obtain and strictly comply with air permits containing various emissions and operational limitations or install emission control equipment. OG&E and Enogex likely will be required to incur certain capital expenditures in the future for air pollution control equipment and technology in connection with obtaining and maintaining operating permits and approvals for air emissions.

Regional Haze Control Measures

On June 15, 2005, the EPA issued final amendments to its 1999 regional haze rule. Regional haze is visibility impairment caused by the cumulative air pollutant emissions from numerous sources over a wide geographic area. These regulations are intended to protect visibility in certain national parks and wilderness areas throughout the United States. In Oklahoma, the Wichita Mountains are the only area covered under the regulation. However, Oklahoma's impact on parks in other states must also be evaluated.

As required by the Federal regional haze rule, the state of Oklahoma evaluated the installation of Best Available Retrofit Technology ("BART") to reduce emissions that cause or contribute to regional haze from certain sources within the state that were built between 1962 and 1977. Certain of OG&E's units at the Horseshoe Lake, Seminole, Muskogee and Sooner generating stations were evaluated for BART. On February 18, 2010, Oklahoma submitted its state implementation plan ("SIP") to the EPA, which set forth the state's plan for compliance with the Federal regional haze rule. The SIP was subject to the EPA's review and approval.

The Oklahoma SIP included requirements for reducing emissions of NOX and SO2 from OG&E's seven BART-eligible units at the Seminole, Muskogee and Sooner generating stations. The SIP also included a waiver from BART requirements for all eligible units at the Horseshoe Lake generating station based on air modeling that showed no significant impact on visibility in nearby national parks and wilderness areas. The SIP concluded that BART for reducing NOX emissions at all of the subject units should be the installation of low NOX burners (overfire air and flue gas recirculation was also required on two of the units) and set forth associated NOX emission rates and limits. OG&E preliminarily estimates that the total cost of installing and operating these NOX controls on all covered units, based on recent industry experience and past projects, will be between $70 million and $130 million. With respect to SO2 emissions, the SIP included an agreement between the Oklahoma Department of Environmental Quality ("ODEQ") and OG&E that established BART for SO2 control at four coal-fired units located at OG&E's Sooner and Muskogee generating stations as the continued use of low sulfur coal (along with associated emission rates and limits). The SIP specifically rejected the installation and operation of Dry Scrubbers as BART for SO2 control from these units because the state determined that Dry Scrubbers were not cost effective on these units.

On December 28, 2011, the EPA rejected portions of the Oklahoma SIP and issued a Federal implementation plan. While the EPA accepted Oklahoma's BART determination for NOX in the SIP, it rejected the SO2 BART determination with respect to the four coal-fired units at the Sooner and Muskogee generating stations. In its place, the EPA is requiring that OG&E meet an SO2 emission rate of 0.06 pounds per MMBtu within five years. OG&E could meet the proposed standard by either installing and operating Dry Scrubbers or fuel switching at the four affected units. OG&E estimates that installing Dry Scrubbers on these units would cost OG&E more than $1.0 billion. OG&E and the state of Oklahoma expect to file an administrative stay request with the EPA. OG&E and the state of Oklahoma have also announced that they intend to petition for review of this determination in the U.S. Court of Appeals for the Tenth Circuit. Neither the outcome of the appeal nor the timing and amount of any required expenditures for pollution control equipment can be predicted with any certainty at this time.

Cross-State Air Pollution Rule

On July 7, 2011, the EPA finalized its Cross-State Air Pollution Rule to replace the former Clean Air Interstate Rule that was remanded by a Federal court as a result of legal challenges. The final rule requires 27 states to reduce power plant emissions that contribute to ozone and particulate matter pollution in other states. On December 27, 2011, the EPA published a supplemental rule which makes six additional states, including Oklahoma, subject to the Cross-State Air Pollution Rule for NOX emissions during the ozone-season from May 1 through September 30. Under the rule, OG&E is required to reduce ozone-season NOX emissions from its electrical generating units within the state beginning in 2012. The Cross-State Air Pollution Rule is currently being challenged in court by numerous states and power generators. On December 30, 2011, the U.S. Court of Appeals issued a stay of the rule and requested proposals for accelerated briefing to allow the merits of the case to be heard by April 2012. On February 6, 2012, the EPA issued a notice indicating that the supplemental rule is also included in the stay discussed above. OG&E cannot predict the outcome of such challenges and is evaluating what emission controls would be necessary to meet the standards, its ability to comply with the standards in the timeframe proposed by the EPA and the associated costs, which could be significant.

Hazardous Air Pollutants Emission Standards

On December 16, 2011, the EPA signed the Maximum Achievable Control Technology regulations governing emissions of certain hazardous air pollutants from electric generating units. The final rule includes numerical standards for particulate matter (as a surrogate for toxic metals), hydrogen chloride and mercury emissions from coal-fired boilers. In addition, the regulations include work practice standards for dioxins and furans. Compliance is required within three years after the effective date of the rule with a possibility of a one year extension. The effective date of the rule has not been established, but it is expected to be during the second quarter of 2012. The final rule could be appealed after it is published. OG&E cannot predict the outcome of any such appeals and is evaluating the regulations and what emission controls would be necessary to meet the standards and the associated costs, which could be significant.

Notice of Violation

In July 2008, OG&E received a request for information from the EPA regarding Federal Clean Air Act compliance at OG&E's Muskogee and Sooner generating plants. In recent years, the EPA has issued similar requests to numerous other electric utilities seeking to determine whether various maintenance, repair and replacement projects should have required permits under the Federal Clean Air Act's new source review process. In January 2012, OG&E received a supplemental request for an update of the previously provided information and for some additional information not previously requested. OG&E believes it has acted in full compliance with the Federal Clean Air Act and new source review process and is cooperating with the EPA. On April 26, 2011, the EPA issued a notice of violation alleging that 13 projects that occurred at OG&E's Muskogee and Sooner generating plants between 1993 and 2006 without the required new source review permits. The notice of violation also alleges that OG&E's visible emissions at its Muskogee and Sooner generating plants are not in accordance with applicable new source performance standards (See Part I, Item 3 – Legal Proceedings – Opacity Notice in the Company's 10-K for a related discussion). OG&E has met with the EPA regarding the notice but cannot predict at this time what, if any, further actions may be necessary as a result of the notice. The EPA could seek to require OG&E to install additional pollution control equipment and pay fines and significant penalties as a result of the allegations in the notice of violation. Section 113 of the Federal Clean Air Act (along with the Federal Civil Penalties Inflation Adjustment Act of 1996) provides for civil penalties as much as $37,500 per day for each violation.

National Ambient Air Quality Standards

The EPA is required to set National Ambient Air Quality Standards ("NAAQS") for certain pollutants considered to be harmful to public health or the environment. On June 2, 2010, the EPA released its final rule strengthening its NAAQS for SO2. The final rule revokes the existing 24-hour and annual standards and establishes a new lower one-hour standard at a level of 75 parts per billion. The EPA intends to complete attainment designations within two years of promulgation of the revised SO2 standard, which is expected by June 2012. States with areas designated nonattainment in 2012 would need to submit a SIP to the EPA by early 2014 outlining actions that those states will take to meet the EPA's revised standards on or before August 2017. The Company will continue to monitor the EPA's attainment designation activities.

On January 25, 2010, the EPA released a rule strengthening the NAAQS for oxides of nitrogen as measured by nitrogen dioxide which became effective March 26, 2011. The rule establishes a new one-hour standard and monitoring requirements, as well as an approach for implementing the new standard. Oklahoma is currently in attainment with the new standard and it is anticipated that Oklahoma will be designated "unclassifiable" in 2012 because the new monitoring requirements will not yet be fully implemented. After the new monitoring network is deployed and has collected three years of air quality data, the EPA will re-designate areas in 2016 or 2017 based on the new data. It is currently anticipated that Oklahoma will be designated "attainment" at that time.

On September 21, 2006, the EPA lowered the 24-hour fine particulate NAAQS while retaining the annual NAAQS at its existing level and promulgated a new standard for inhalable coarse particulates. Based on past monitoring data, it appears that Oklahoma may be able to remain in attainment with these standards. However if parts of Oklahoma do become "non-attainment", reductions in emissions from OG&E's coal-fired boilers could be required which may result in significant capital and operating expenditures.

The EPA has designated Oklahoma as being "in attainment" with the current NAAQS for ozone. In March 2008, the EPA issued a final rule lowering the ambient primary and secondary ozone standards NAAQS from current levels. Before Oklahoma's designations of areas as attaining or not attaining the 2008 ozone standards were complete, the EPA announced an intent to reconsider these standards and issue even lower ozone NAAQS. President Obama, however, requested that the EPA refrain from issuing revised standards until 2013. The EPA has indicated that it will comply with the President's request. As a result, it is expected that Oklahoma will proceed with the designation of areas as attaining or not attaining the ozone standards established in the 2008 rule. Neither the outcome nor timing of the ozone NAAQS attainment area designation process nor its impact on the Company can be determined with any certainty at this time.

Acid Rain Program

The Federal Clean Air Act includes an Acid Rain Program. The goal of the Acid Rain Program is to achieve environmental and public health benefits through reductions in SO2 and NOX emissions, which are the primary causes of acid rain. To achieve this goal, the program employs both traditional and market-based approaches for controlling air pollution.

The Acid Rain Program introduces an allowance trading system that uses the free market to reduce pollution. Under this system, affected utility units are allocated allowances based on their historic fuel consumption and a specific emissions rate. Each allowance permits a unit to emit one ton of SO2 from the chimney during or after a specified year. For each ton of SO2 emitted in a given year, one allowance is retired, that is, it can no longer be used. Allowances may be bought, sold or banked.

During Phase II of the program (now in effect), the Federal Clean Air Act set a permanent ceiling (or cap) of 8.95 million total annual allowances allocated to utilities. This cap firmly restricts emissions and ensures that environmental benefits will be achieved and maintained. Due to OG&E's earlier decision to burn low sulfur coal, these restrictions have had no significant financial impact.

The Acid Rain Program also focuses on one set of sources that emit NOX, coal-fired electric utility boilers. As with the SO2 emission reduction requirements, the NOX program was implemented in two phases, beginning in 1996 and 2000. The NOX program embodies many of the same principles of the SO2 trading program. However, it does not cap NOX emissions as the SO2 program does, nor does it utilize an allowance trading system.

Emission limitations for NOX focus on the emission rate to be achieved (expressed in pounds of NOX per MMBtu of heat input). In general, two options for compliance with the emission limitations are provided: compliance with an individual emission rate for a boiler; or averaging of emission rates over two or more units to meet an overall emission rate limitation.

Since becoming subject to the Acid Rain Program, OG&E has met all obligations and limitations requirements.

Climate Change and Greenhouse Gas Emissions

Emissions of greenhouse gases, including carbon dioxide, sulfur hexafluoride and methane, may be contributing to warming of the Earth's atmosphere. There are various international agreements that restrict greenhouse gas emissions, but none of them have a binding effect on sources located in the United States. The U.S. Congress has not passed legislation to reduce emissions of greenhouse gases and the future prospects for any such legislation are uncertain. Several states have passed laws, adopted regulations or undertaken regulatory initiatives to reduce the emission of greenhouse gases, primarily through the planned development of greenhouse gas emission inventories and/or regional greenhouse gas cap and trade programs. Oklahoma, Arkansas and Texas are not among them.

In the absence of new Federal legislation, the EPA is regulating greenhouse gas emissions from stationary sources using its existing legal authority. On September 22, 2009, the EPA announced the adoption of the first comprehensive national system for reporting emissions of carbon dioxide and other greenhouse gases produced by major sources in the United States. The reporting requirements apply to large direct emitters of greenhouse gases with emissions equal to or greater than a threshold of 25,000 metric tons per year, which includes certain OG&E and Enogex facilities. Pursuant to the rule, the Company began collecting data on January 1, 2010 and submitted its first annual report to the EPA by the September 30, 2011 deadline. For petroleum and natural gas facilities, data collection began on January 1, 2011, with the first annual report due to the EPA on September 28, 2012. OG&E already reports quarterly its carbon dioxide emissions from generating units subject to the Federal Acid Rain Program.

On June 3, 2010, the EPA issued a final rule that makes certain sources subject to permitting requirements for greenhouse gas emissions. This rule now requires sources that emit greater than 100,000 tons per year of greenhouse gases to obtain a permit for those emissions, even if they are not otherwise required to obtain a new or modified permit. Such sources may have to install best available control technology to control greenhouse gas emissions pursuant to this rule. Also, in December 2010, the EPA entered into an agreement to settle litigation brought by states and environmental groups whereby the EPA agreed to issue New Source Performance Standards for greenhouse gas emissions from certain new and modified electric generating units and emissions guidelines for existing units over the next two years. Pursuant to this settlement agreement, the EPA agreed to issue proposed rules during the fourth quarter of 2011 and final rules by mid-2012. The EPA has not yet issued proposed rules and has sought to extend the deadlines for issuing the rules.

Another impetus for addressing climate change is litigation relating to greenhouse gas emissions and pressure for greenhouse gas emission reductions from investor organizations and the international community. In at least three Federal court cases, nuisance-type claims have been asserted against emitters of carbon dioxide, including several utility companies, alleging that such emissions contribute to global warming. On June 20, 2011, the U.S. Supreme Court issued a decision that bars state and private parties from bringing Federal common law nuisance actions against electrical utility companies based on their alleged contribution to climate change. The Supreme Court's decision, which did not address state law claims, is expected to affect other pending Federal climate change litigation. Although OG&E is not a defendant in any of these proceedings, additional litigation in Federal and state courts over climate change issues is continuing.

OG&E is continuing to evaluate various options for reducing, avoiding, offsetting or sequestering its carbon dioxide emissions. OG&E is a partner in the EPA Sulfur Hexafluoride Voluntary Reduction Program, and Enogex is a partner in the EPA Natural Gas STAR Program, a voluntary program to reduce methane emissions.

If legislation or regulations are passed at the Federal or state levels in the future requiring mandatory reductions of carbon dioxide and other greenhouse gases on facilities to address climate change, this could result in significant additional compliance costs that would affect the Company's future consolidated financial position, results of operations and cash flows if such costs are not recovered through regulated rates.

Endangered Species

Certain Federal laws, including the Bald and Golden Eagle Protection Act, the Migratory Bird Treaty Act and the Endangered Species Act, provide special protection to certain designated species. These laws and any state equivalents provide for significant civil and criminal penalties for unpermitted activities that result in harm to or harassment of certain protected animals and plants, including damage to their habitats. If such species are located in an area in which the Company conducts operations, or if additional species in those areas, such as the lesser prairie chicken, become subject to protection, the Company's operations and development projects, particularly transmission projects, wind projects or pipeline operations, could be restricted or delayed, or the Company could be required to implement expensive mitigation measures.

Waste

OG&E's and Enogex's operations generate hazardous wastes that are subject to the Federal Resource Conservation and Recovery Act of 1976 as well as comparable state laws which impose detailed requirements for the handling, storage, treatment and disposal of hazardous waste.

For OG&E, these laws impose strict "cradle to grave" requirements on generators regarding their treatment, storage and disposal of hazardous waste. OG&E routinely generates small quantities of hazardous waste throughout its system and occasional larger quantities from periodic power generation related activities. These wastes are treated, stored and disposed at facilities that are permitted to manage them.

In June 2010, the EPA proposed new rules under Federal Resource Conservation and Recovery Act of 1976 that could alter the classification of OG&E's coal-fired power plants as conditionally exempt hazardous waste generators and make the management of coal ash more costly. The extent to which the EPA intends to regulate coal ash is uncertain due to the fact that the new rules propose to regulate coal ash as a hazardous waste or as a nonhazardous solid waste. In November 2010, OG&E submitted written comments opposing the regulation of coal ash as a hazardous waste while supporting its regulation as a nonhazardous waste. The EPA continues to consider numerous comments received on the proposal and has stated that it plans to issue a final rule regarding the regulation of coal ash in late 2012.

OG&E has sought and will continue to seek pollution prevention opportunities and to evaluate the effectiveness of its waste reduction, reuse and recycling efforts. In 2011, OG&E obtained refunds of $5.2 million from the recycling of scrap metal, salvaged transformers and used transformer oil. This figure does not include the additional savings gained through the reduction and/or avoidance of disposal costs and the reduction in material purchases due to the reuse of existing materials. Similar savings are anticipated in future years.

For Enogex, the Federal Resource Conservation and Recovery Act of 1976 currently exempts many natural gas gathering and field processing wastes from classification as hazardous waste. However, these oil and gas exploration and production wastes may still be regulated under state law or the less stringent solid waste requirements of the Federal Resource Conservation and Recovery Act of 1976. The transportation of natural gas in pipelines may also generate some hazardous wastes that are subject to the Federal Resource Conservation and Recovery Act of 1976 or comparable state law requirements.

Water

OG&E's and Enogex's operations are subject to the Federal Water Pollution Control Act of 1972, as amended ("Federal Clean Water Act"), and analogous state laws and regulations. These laws and regulations impose detailed requirements and strict controls regarding the discharge of pollutants into state and Federal waters. The discharge of pollutants, including discharges resulting from a spill or leak, is prohibited unless authorized by a permit or other agency approval. The Federal Clean Water Act and regulations implemented thereunder also prohibit discharges of dredged and fill material in wetlands and other waters of the United States unless authorized by an appropriately issued permit. Existing cooling water intake structures are regulated under the Federal Clean Water Act to minimize their impact on the environment.

With respect to cooling water intake structures, Section 316(b) of the Federal Clean Water Act requires that their location, design, construction and capacity reflect the "best available technology" for minimizing their adverse environmental impact via the impingement and entrainment of aquatic organisms. In March 2011, the EPA proposed rules to implement Section 316(b). On August 18, 2011, OG&E filed comments with the EPA on the proposed rules. OG&E anticipates that the proposed rules will be finalized in mid-2012. In the interim, the state of Oklahoma requires OG&E to implement best management practices related to the operation and maintenance of its existing cooling water intake structures as a condition of renewing its discharge permits. Once the EPA promulgates the final rules, OG&E may incur additional capital and/or operating costs to comply with them. The costs of complying with the final water intake standards are not currently determinable, but could be significant.

Site Remediation

The Comprehensive Environmental Response, Compensation and Liability Act of 1980 and comparable state laws impose liability, without regard to the legality of the original conduct, on certain classes of persons responsible for the release of hazardous substances into the environment. Because OG&E and Enogex utilize various products and generate wastes that are considered hazardous substances for purposes of the Comprehensive Environmental Response, Compensation and Liability Act of 1980, OG&E and Enogex could be subject to liability for the costs of cleaning up and restoring sites where those substances have been released to the environment. At this time, it is not anticipated that any associated liability will cause a significant impact to OG&E or Enogex.

For a further discussion regarding contingencies relating to environmental laws and regulations, see Note 16 of Notes to Consolidated Financial Statements.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Market risks are, in most cases, risks that are actively traded in a marketplace and have been well studied in regards to quantification. Market risks include, but are not limited to, changes in interest rates and commodity prices. The Company's exposure to changes in interest rates relates primarily to short-term variable-rate debt and commercial paper. The Company is exposed to commodity prices in its operations.

Risk Committee and Oversight

Management monitors market risks using a risk committee structure. The Company's Risk Oversight Committee, which consists primarily of corporate officers, is responsible for the overall development, implementation and enforcement of strategies and policies for all market risk management activities of the Company. This committee's emphasis is a holistic perspective of risk measurement and policies targeting the Company's overall financial performance. The Risk Oversight Committee is authorized by, and reports quarterly to, the Audit Committee of the Company's Board of Directors.

The Unregulated Business Unit Risk Management Committee is comprised primarily of business unit leaders within Enogex. This committee's purpose is to develop and maintain risk policies for Enogex, to provide oversight and guidance for existing and prospective Enogex business activities and to provide governance regarding compliance with Enogex risk policies. This group is authorized by and reports to the Risk Oversight Committee.

The Company also has a Corporate Risk Management Department led by the Company's Chief Risk Officer. This group, in conjunction with the aforementioned committees, is responsible for establishing and enforcing the Company's risk policies.

Risk Policies

Management utilizes risk policies to control the amount of market risk exposure. These policies are designed to provide the Audit Committee of the Company's Board of Directors and senior executives of the Company with confidence that the risks taken on by the Company's business activities are in accordance with their expectations for financial returns and that the approved policies and controls related to market risk management are being followed. Some of the measures in these policies include value-at-risk limits, position limits, tenor limits and stop loss limits.

Interest Rate Risk

The Company's exposure to changes in interest rates primarily relates to short-term variable-rate debt and commercial paper. The Company manages its interest rate exposure by monitoring and limiting the effects of market changes in interest rates. The Company utilizes interest rate derivatives to alter interest rate exposure in an attempt to reduce the effects of these changes. Interest rate derivatives are used solely to modify interest rate exposure and not to modify the overall leverage of the debt portfolio.

The fair value of the Company's long-term debt is based on quoted market prices and estimates of current rates available for similar issues with similar maturities. The following table shows the Company's long-term debt maturities and the weighted-average interest rates by maturity date.

(Dollars in millions, year ended December 31)	2012	2013	2014	2015	2016	Thereafter	Total	12/31/11 Fair Value
Fixed-rate debt(A)								
Principal amount	$ –	$ –	$300.0	$ –	$110.0	$2,050.0	$2,460.0	$2,990.2
Weighted-average interest rate	–	–	6.25%	–	5.15%	6.40%	6.32%	
Variable-rate debt(B)								
Principal amount	$ –	$ –	$ –	$ –	$150.0	$ 135.4	$ 285.4	$ 285.4
Weighted-average interest rate	–	–	–	–	1.65%	0.22%	0.97%	

(A) *Prior to or when these debt obligations mature, the Company may refinance all or a portion of such debt at then-existing market interest rates which may be more or less than the interest rates on the maturing debt.*

(B) *A hypothetical change of 100 basis points in the underlying variable interest rate incurred by the Company would change interest expense by $2.9 million annually.*

Commodity Price Risk

The commodity price risks inherent in the Company's commodity price sensitive instruments, positions and anticipated commodity transactions are the potential losses in value arising from adverse changes in the commodity prices to which the Company is exposed. These risks can be classified as trading, which includes transactions that are entered into voluntarily to capture subsequent changes in commodity prices, or non-trading, which includes the exposure some of the Company's assets have to commodity prices.

Trading activities are conducted throughout the year subject to $2.5 million daily and monthly trading stop loss limits set by the Risk Oversight Committee. The loss exposure from trading activities is measured primarily using value-at-risk, which estimates the potential losses the trading activities could incur over a specified time horizon and confidence level. Currently, the Company utilizes the variance/co-variance method for calculating value-at-risk, assuming a 95 percent confidence level. The value-at-risk limit set by the Risk Oversight Committee for the Company's trading activities is currently $1.5 million. These limits are designed to mitigate the possibility of trading activities having a material adverse effect on the Company's operating income.

A sensitivity analysis has been prepared to estimate the Company's exposure to commodity price risk created by trading activities. The value of trading positions is a summation of the fair values calculated for each net commodity position based upon quoted market prices. Commodity price risk is estimated as the potential loss in fair value resulting from a hypothetical 20 percent adverse change in quoted market prices. The result of this analysis, which may differ from actual results, reflects net commodity price risk to be $0.1 million at December 31, 2011. This amount represents the Company's exposure, net of the ArcLight group's proportional share.

Commodity price risk is present in the Company's non-trading activities because changes in the prices of natural gas, NGLs and NGLs processing spreads have a direct effect on the compensation the Company receives for operating some of its assets. These prices are subject to fluctuations resulting from changes in supply and demand. To partially reduce non-trading commodity price risk, the Company utilizes risk mitigation tools such as default processing fees and ethane rejection capabilities to protect its downside exposure while maintaining its upside potential. Additionally, the Company hedges, through the utilization of derivatives and other forward transactions, the effects these market fluctuations have on the Company's operating income. Because the commodities covered by these hedges are substantially the same commodities that the Company buys and sells in the physical market, no special studies other than monitoring the degree of correlation between the derivative and cash markets are deemed necessary.

A sensitivity analysis has been prepared to estimate the Company's exposure to commodity price risk created by non-trading activities. The Company's daily net commodity position consists of natural gas inventories, commodity purchase and sales contracts, financial and commodity derivative instruments and anticipated natural gas processing spreads and fuel recoveries. Quoted market prices are not available for all of the Company's non-trading positions; therefore, the value of non-trading positions is a summation of the forecasted values calculated for each commodity based upon internally generated forward price curves. Commodity price risk is estimated as the potential loss in fair value resulting from a hypothetical 20 percent adverse change in quoted market prices. The result of this analysis, which may differ from actual results, reflects net commodity price risk to be $32.0 million at December 31, 2011. This amount represents the Company's exposure, net of the ArcLight group's proportional share.

CONSOLIDATED STATEMENTS OF INCOME

(In millions, except per share data, year ended December 31)	**2011**	2010	2009
Operating revenues			
Electric Utility operating revenues	**$2,211.5**	$2,109.9	$1,751.2
Natural Gas Midstream Operations operating revenues	**1,704.4**	1,607.0	1,118.5
Total operating revenues	**3,915.9**	3,716.9	2,869.7
Cost of goods sold (exclusive of depreciation and amortization shown below)			
Electric Utility cost of goods sold	**966.0**	952.6	748.7
Natural Gas Midstream Operations cost of goods sold	**1,311.9**	1,234.8	809.0
Total cost of goods sold	**2,277.9**	2,187.4	1,557.7
Gross margin on revenues	**1,638.0**	1,529.5	1,312.0
Operating expenses			
Other operation and maintenance	**581.2**	549.8	466.8
Depreciation and amortization	**307.1**	291.3	262.6
Impairment of assets	**6.3**	1.1	3.1
Gain on insurance proceeds	**(3.0)**	–	–
Taxes other than income	**99.7**	93.4	87.6
Total operating expenses	**991.3**	935.6	820.1
Operating income	**646.7**	593.9	491.9
Other income (expense)			
Interest income	**0.5**	–	1.4
Allowance for equity funds used during construction	**20.4**	11.4	15.1
Other income	**19.3**	13.7	27.5
Other expense	**(21.7)**	(17.9)	(16.3)
Net other income	**18.5**	7.2	27.7
Interest expense			
Interest on long-term debt	**146.1**	139.3	137.3
Allowance for borrowed funds used during construction	**(10.4)**	(5.5)	(8.3)
Interest on short-term debt and other interest charges	**5.2**	5.9	8.4
Interest expense	**140.9**	139.7	137.4
Income before taxes	**524.3**	461.4	382.2
Income tax expense	**160.7**	161.0	121.1
Net income	**363.6**	300.4	261.1
Less: net income attributable to noncontrolling interests	**20.7**	5.1	2.8
Net income attributable to OGE Energy	**$ 342.9**	$ 295.3	$ 258.3
Basic average common shares outstanding	**97.9**	97.3	96.2
Diluted average common shares outstanding	**99.2**	98.9	97.2
Basic earnings per average common share attributable to OGE Energy common shareholders	**$ 3.50**	$ 3.03	$ 2.68
Diluted earnings per average common share attributable to OGE Energy common shareholders	**$ 3.45**	$ 2.99	$ 2.66
Dividends declared per common share	**$ 1.5175**	$ 1.4625	$ 1.4275

The accompanying Notes to Consolidated Financial Statements are an integral part hereof.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(In millions, year ended December 31)	**2011**	2010	2009
Net income	**$363.6**	$300.4	$261.1
Other comprehensive income (loss), net of tax			
Pension plan and restoration of retirement income plan:			
Amortization of deferred net loss, net of tax of $1.4 million, $1.2 million and $2.0 million, respectively	**2.5**	1.3	3.2
Net gain (loss) arising during the period, net of tax of ($6.7) million, $4.4 million and $0.4 million, respectively	**(13.5)**	7.6	0.6
Amortization of prior service cost, net of tax of $0.2 million, $0.1 million and $0.1 million, respectively	**0.4**	0.2	0.1
Prior service cost arising during the period, net of tax of $0, $0 and ($0.2) million, respectively	**–**	–	(0.3)
Postretirement plans:			
Amortization of deferred net loss, net of tax of ($1.6) million, $0.6 million and $0.7 million, respectively	**1.8**	1.2	0.9
Net loss arising during the period, net of tax of ($3.1) million, ($2.4) million and ($4.1) million, respectively	**(3.6)**	(4.1)	(6.3)
Amortization of deferred net transition obligation, net of tax of $0.1 million, $0.1 million and $0.1 million, respectively	**0.2**	0.1	0.1
Amortization of prior service cost, net of tax of ($1.6) million, $0.1 million and $0.1 million, respectively	**(1.8)**	–	0.2
Prior service cost arising during the period, net of tax of $9.5 million, $0 and $0, respectively	**10.8**	–	–
Deferred commodity contracts hedging losses reclassified in net income, net of tax of $12.6 million, $9.9 million and $4.7 million, respectively	**27.6**	18.5	7.5
Deferred commodity contracts hedging gains (losses), net of tax of ($1.7) million, ($8.5) million and ($42.6) million, respectively	**(4.8)**	(16.3)	(67.3)
Deferred interest rate swaps hedging gains, net of tax of $0.2 million, $0.2 million and $0.2 million, respectively	**0.3**	0.2	0.3
Other comprehensive income (loss), net of tax	**19.9**	8.7	(61.0)
Comprehensive income (loss)	**383.5**	309.1	200.1
Less: Comprehensive income attributable to noncontrolling interest for sale of equity investment	**(3.2)**	(6.2)	–
Less: Comprehensive income attributable to noncontrolling interests	**24.2**	5.5	2.8
Total comprehensive income (loss) attributable to OGE Energy	**$362.5**	$309.8	$197.3

The accompanying Notes to Consolidated Financial Statements are an integral part hereof.

CONSOLIDATED STATEMENTS OF CASH FLOWS

(In millions, year ended December 31)	2011	2010	2009
Cash flows from operating activities			
Net income	**$ 363.6**	$ 300.4	$ 261.1
Adjustments to reconcile net income to net cash provided from operating activities			
Depreciation and amortization	**307.1**	291.3	262.6
Impairment of assets	**6.3**	1.1	3.1
Deferred income taxes and investment tax credits, net	**166.0**	146.4	269.8
Allowance for equity funds used during construction	**(20.4)**	(11.4)	(15.1)
Gain on disposition and abandonment of assets	**(2.7)**	–	–
Gain on insurance proceeds	**(3.0)**	–	–
Stock-based compensation expense	**7.8**	7.4	4.1
Excess tax benefit on stock-based compensation	**–**	(0.7)	(3.3)
Price risk management assets	**(1.7)**	3.9	27.8
Price risk management liabilities	**19.0**	8.5	(88.7)
Regulatory assets	**14.0**	24.1	20.2
Regulatory liabilities	**(1.9)**	(12.4)	(17.5)
Other assets	**(7.0)**	6.3	(3.5)
Other liabilities	**(37.4)**	(37.0)	(37.7)
Change in certain current assets and liabilities			
Accounts receivable, net	**(48.0)**	11.9	(3.3)
Accrued unbilled revenues	**(2.5)**	0.4	(10.2)
Income taxes receivable	**(3.6)**	153.0	(157.7)
Fuel, materials and supplies inventories	**54.2**	(45.2)	(36.1)
Gas imbalance assets	**0.7**	0.7	3.0
Fuel clause under recoveries	**(0.8)**	(0.7)	23.7
Other current assets	**(7.2)**	(5.9)	(1.4)
Accounts payable	**34.5**	59.2	(17.2)
Gas imbalance liabilities	**3.1**	(5.3)	(12.9)
Fuel clause over recoveries	**(22.2)**	(157.6)	178.9
Other current liabilities	**16.0**	44.1	4.8
Net cash provided from operating activities	**833.9**	782.5	654.5
Cash flows from investing activities			
Capital expenditures (less allowance for equity funds used during construction)	**(1,270.4)**	(879.9)	(847.8)
Acquisition of gathering assets	**(200.4)**	–	–
Reimbursement of capital expenditures	**49.6**	31.5	38.8
Proceeds from sale of assets	**18.0**	2.3	–
Proceeds from insurance	**7.4**	–	–
Other investing activities	**–**	–	0.5
Net cash used in investing activities	**(1,395.8)**	(846.1)	(808.5)
Cash flows from financing activities			
Proceeds from long-term debt	**246.3**	246.2	444.8
Contributions from noncontrolling interest partners	**216.4**	183.2	–
Proceeds from line of credit	**150.0**	115.0	80.0
Increase (decrease) in short-term debt	**132.1**	(30.0)	(123.0)
Issuance of common stock	**14.8**	16.9	79.6
Excess tax benefit on stock-based compensation	**–**	0.7	3.3
Retirement of long-term debt	**–**	(289.2)	(110.8)
Purchase of treasury stock	**(6.2)**	–	–
Distributions to noncontrolling interest partners	**(17.4)**	(4.0)	–
Repayment of line of credit	**(25.0)**	(90.0)	(200.0)
Dividends paid on common stock	**(146.8)**	(141.0)	(136.2)
Net cash provided from financing activities	**564.2**	7.8	37.7
Net increase (decrease) in cash and cash equivalents	**2.3**	(55.8)	(116.3)
Cash and cash equivalents at beginning of period	**2.3**	58.1	174.4
Cash and cash equivalents at end of period	**$ 4.6**	$ 2.3	$ 58.1

The accompanying Notes to Consolidated Financial Statements are an integral part hereof.

CONSOLIDATED BALANCE SHEETS

(In millions, December 31)	2011	2010
Assets		
Current assets		
Cash and cash equivalents	**$ 4.6**	$ 2.3
Accounts receivable, less reserve of $3.8 and $1.9, respectively	**322.5**	277.9
Accrued unbilled revenues	**59.3**	56.8
Income taxes receivable	**8.3**	4.7
Fuel inventories	**100.7**	158.8
Materials and supplies, at average cost	**87.2**	83.3
Price risk management	**3.5**	1.4
Gas imbalances	**1.8**	2.5
Deferred income taxes	**32.1**	18.7
Fuel clause under recoveries	**1.8**	1.0
Other	**30.9**	24.7
Total current assets	**652.7**	632.1
Other property and investments, at cost	**46.7**	44.9
Property, plant and equipment		
In service	**10,315.9**	9,188.0
Construction work in progress	**499.0**	460.0
Total property, plant and equipment	**10,814.9**	9,648.0
Less accumulated depreciation	**3,340.9**	3,183.6
Net property, plant and equipment	**7,474.0**	6,464.4
Deferred charges and other assets		
Regulatory assets	**507.9**	489.4
Intangible assets, net	**137.0**	2.8
Goodwill	**39.4**	–
Price risk management	**0.3**	0.8
Other	**48.0**	34.7
Total deferred charges and other assets	**732.6**	527.7
Total assets	**$ 8,906.0**	$7,669.1

The accompanying Notes to Consolidated Financial Statements are an integral part hereof.

(In millions, December 31)	2011	2010
Liabilities and stockholders' equity		
Current liabilities		
Short-term debt	**$ 277.1**	$ 145.0
Accounts payable	**388.0**	321.7
Dividends payable	**38.5**	36.6
Customer deposits	**67.6**	67.0
Accrued taxes	**42.3**	39.3
Accrued interest	**54.8**	53.1
Accrued compensation	**47.8**	43.3
Price risk management	**0.4**	16.8
Gas imbalances	**9.8**	6.7
Fuel clause over recoveries	**7.7**	29.9
Other	**64.5**	55.1
Total current liabilities	**998.5**	814.5
Long-term debt	**2,737.1**	2,362.9
Deferred credits and other liabilities		
Accrued benefit obligations	**360.8**	372.4
Deferred income taxes	**1,651.4**	1,434.8
Deferred investment tax credits	**6.1**	9.4
Regulatory liabilities	**230.7**	193.1
Price risk management	**0.1**	–
Deferred revenues	**40.8**	36.7
Other	**61.2**	45.3
Total deferred credits and other liabilities	**2,351.1**	2,091.7
Total liabilities	**6,086.7**	5,269.1
Commitments and contingencies (note 16)		
Stockholders' equity		
Common stockholders' equity	**1,035.3**	969.2
Retained earnings	**1,574.8**	1,380.6
Accumulated other comprehensive loss, net of tax	**(40.6)**	(60.2)
Treasury stock, at cost	**(6.2)**	–
Total OGE Energy stockholders' equity	**2,563.3**	2,289.6
Noncontrolling interests	**256.0**	110.4
Total stockholders' equity	**2,819.3**	2,400.0
Total liabilities and stockholders' equity	**$8,906.0**	$7,669.1

The accompanying Notes to Consolidated Financial Statements are an integral part hereof.

CONSOLIDATED STATEMENTS OF CAPITALIZATION

(In millions, December 31)	2011	2010
Stockholders' equity		
Common stock, par value $0.01 per share; authorized 225.0 shares; and outstanding 98.1 and 97.6 shares, respectively	**$ 1.0**	$ 1.0
Premium on common stock	**1,034.3**	968.2
Retained earnings	**1,574.8**	1,380.6
Accumulated other comprehensive loss, net of tax	**(40.6)**	(60.2)
Treasury stock, at cost, 0.1 and 0 shares, respectively	**(6.2)**	–
Total OGE Energy stockholders' equity	**2,563.3**	2,289.6
Noncontrolling interest	**256.0**	110.4
Total stockholders' equity	**2,819.3**	2,400.0
Long-term debt		
Senior Notes – OGE Energy		
5.00% Senior Notes, Series Due November 15, 2014	**100.0**	100.0
Unamortized discount	**(0.2)**	(0.3)
Senior Notes – OG&E		
5.15% Senior Notes, Series Due January 15, 2016	**110.0**	110.0
6.50% Senior Notes, Series Due July 15, 2017	**125.0**	125.0
6.35% Senior Notes, Series Due September 1, 2018	**250.0**	250.0
8.25% Senior Notes, Series Due January 15, 2019	**250.0**	250.0
6.65% Senior Notes, Series Due July 15, 2027	**125.0**	125.0
6.50% Senior Notes, Series Due April 15, 2028	**100.0**	100.0
6.50% Senior Notes, Series Due August 1, 2034	**140.0**	140.0
5.75% Senior Notes, Series Due January 15, 2036	**110.0**	110.0
6.45% Senior Notes, Series Due February 1, 2038	**200.0**	200.0
5.85% Senior Notes, Series Due June 1, 2040	**250.0**	250.0
5.25% Senior Notes, Series Due May 15, 2041	**250.0**	–
Other Bonds – OG&E		
0.22% – 0.44% Garfield Industrial Authority, January 1, 2025	**47.0**	47.0
0.20% – 0.44% Muskogee Industrial Authority, January 1, 2025	**32.4**	32.4
0.24% – 0.50% Muskogee Industrial Authority, June 1, 2027	**56.0**	56.0
Unamortized discount	**(6.2)**	(5.0)
Enogex		
1.65% Enogex LLC Revolving Credit Agreement Due December 13, 2016	**150.0**	25.0
6.875% Senior Notes, Series Due July 15, 2014	**200.0**	200.0
6.25% Senior Notes, Series Due March 15, 2020	**250.0**	250.0
Unamortized discount	**(1.9)**	(2.2)
Total long-term debt	**2,737.1**	2,362.9
Total Capitalization	**$5,556.4**	$4,762.9

The accompanying Notes to Consolidated Financial Statements are an integral part hereof.

CONSOLIDATED STATEMENTS OF CHANGES IN STOCKHOLDERS' EQUITY

(In millions)	Common Stock	Premium on Common Stock	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interest	Treasury Stock	Total
Balance at December 31, 2008	$0.9	$ 802.0	$1,107.6	$(13.7)	$ 17.2	$ –	$1,914.0
Comprehensive income (loss)							
Net income	–	–	258.3	–	2.8	–	261.1
Other comprehensive income (loss), net of tax	–	–	–	(61.0)	–	–	(61.0)
Comprehensive income (loss)	–	–	258.3	(61.0)	2.8	–	200.1
Dividends declared on common stock	–	–	(138.1)	–	–	–	(138.1)
Issuance of common stock	0.1	79.5	–	–	–	–	79.6
Stock-based compensation	–	5.2	–	–	–	–	5.2
Balance at December 31, 2009	$1.0	$ 886.7	$1,227.8	$(74.7)	$ 20.0	–	$2,060.8
Comprehensive income (loss)							
Net income	–	–	295.3	–	5.1	–	300.4
Other comprehensive income (loss), net of tax	–	–	–	14.5	(5.8)	–	8.7
Comprehensive income (loss)	–	–	295.3	14.5	(0.7)	–	309.1
Dividends declared on common stock	–	–	(142.5)	–	–	–	(142.5)
Issuance of common stock	–	17.0	–	–	–	–	17.0
Stock-based compensation	–	10.4	–	–	–	–	10.4
Contributions from noncontrolling interest partner	–	88.1	–	–	95.1	–	183.2
Deferred income taxes attributable to contributions from noncontrolling interest partner	–	(34.0)	–	–	–	–	(34.0)
Distributions to noncontrolling interest partner	–	–	–	–	(4.0)	–	(4.0)
Balance at December 31, 2010	$1.0	$ 968.2	$1,380.6	$(60.2)	$110.4	–	$2,400.0
Comprehensive income (loss)							
Net income	–	–	**342.9**	–	**20.7**	–	**363.6**
Other comprehensive income (loss), net of tax	–	–	–	**19.6**	**0.3**	–	**19.9**
Comprehensive income (loss)	–	–	**342.9**	**19.6**	**21.0**	–	**383.5**
Dividends declared on common stock	–	–	**(148.7)**	–	–	–	**(148.7)**
Issuance of common stock	–	**14.8**	–	–	–	–	**14.8**
Stock-based compensation	–	**5.8**	–	–	–	–	**5.8**
Contributions from noncontrolling interest partners	–	**74.4**	–	–	**142.0**	–	**216.4**
Distributions to noncontrolling interest partners	–	–	–	–	**(17.4)**	–	**(17.4)**
Deferred income taxes attributable to contributions from noncontrolling interest partners	–	**(28.9)**	–	–	–	–	**(28.9)**
Purchase of treasury stock	–	–	–	–	–	**(6.2)**	**(6.2)**
Balance at December 31, 2011	**$1.0**	**$1,034.3**	**$1,574.8**	**$(40.6)**	**$256.0**	**$(6.2)**	**$2,819.3**

The accompanying Notes to Consolidated Financial Statements are an integral part hereof.

1. Summary of Significant Accounting Policies

Organization

The Company is an energy and energy services provider offering physical delivery and related services for both electricity and natural gas primarily in the south central United States. The Company conducts these activities through four business segments: (i) electric utility, (ii) natural gas transportation and storage, (iii) natural gas gathering and processing and (iv) natural gas marketing. All significant intercompany transactions have been eliminated in consolidation.

The electric utility segment generates, transmits, distributes and sells electric energy in Oklahoma and western Arkansas. Its operations are conducted through OG&E and are subject to regulation by the OCC, the APSC and the FERC. OG&E was incorporated in 1902 under the laws of the Oklahoma Territory. OG&E is the largest electric utility in Oklahoma and its franchised service territory includes the Fort Smith, Arkansas area. OG&E sold its retail natural gas business in 1928 and is no longer engaged in the natural gas distribution business.

Enogex is a provider of integrated natural gas midstream services. Enogex is engaged in the business of gathering, processing, transporting, storing and marketing natural gas. Most of Enogex's natural gas gathering, processing, transportation and storage assets are strategically located in the Arkoma and Anadarko basins of Oklahoma and the Texas Panhandle. Enogex's operations are organized into three business segments: (i) natural gas transportation and storage, (ii) natural gas gathering and processing and (iii) natural gas marketing. At December 31, 2011, the Company indirectly owns an 81.3 percent membership interest in Enogex Holdings, which in turn owns all of the membership interests in Enogex LLC, a Delaware single-member limited liability company (see Note 4). The Company continues to consolidate Enogex Holdings in its Consolidated Financial Statements as OGE Energy has a controlling financial interest over the operations of Enogex Holdings. Also, Enogex LLC holds a 50 percent ownership interest in Atoka. The Company consolidates Atoka in its Consolidated Financial Statements as Enogex acts as the managing member of Atoka and has control over the operations of Atoka.

OGE Energy charges operating costs to its subsidiaries based on several factors. Operating costs directly related to specific subsidiaries are assigned to those subsidiaries. Where more than one subsidiary benefits from certain expenditures, the costs are shared between those subsidiaries receiving the benefits. Operating costs incurred for the benefit of all subsidiaries are allocated among the subsidiaries, either as overhead based primarily on labor costs or using the "Distrigas" method. The Distrigas method is a three-factor formula that uses an equal weighting of payroll, net operating revenues and gross property, plant and equipment. OGE Energy adopted the Distrigas method in January 1996 as a result of a recommendation by the OCC Staff. OGE Energy believes this method provides a reasonable basis for allocating common expenses.

Basis of Presentation

In the opinion of management, all adjustments necessary to fairly present the consolidated financial position of the Company at December 31, 2011 and 2010 and the results of its operations and cash flows for the years ended December 31, 2011, 2010 and 2009, have been included and are of a normal recurring nature except as otherwise disclosed.

Accounting Records

The accounting records of OG&E are maintained in accordance with the Uniform System of Accounts prescribed by the FERC and adopted by the OCC and the APSC. Additionally, OG&E, as a regulated utility, is subject to accounting principles for certain types of rate-regulated activities, which provide that certain actual or anticipated costs that would otherwise be charged to expense can be deferred as regulatory assets, based on the expected recovery from customers in future rates. Likewise, certain actual or anticipated credits that would otherwise reduce expense can be deferred as regulatory liabilities, based on the expected flowback to customers in future rates. Management's expected recovery of deferred costs and flowback of deferred credits generally results from specific decisions by regulators granting such ratemaking treatment.

OG&E records certain actual or anticipated costs and obligations as regulatory assets or liabilities if it is probable, based on regulatory orders or other available evidence, that the cost or obligation will be included in amounts allowable for recovery or refund in future rates.

The following table is a summary of OG&E's regulatory assets and liabilities at:

(In millions, December 31)	2011	2010
Regulatory assets		
Current		
Fuel clause under recoveries	**$ 1.8**	$ 1.0
Other[A]	**14.2**	4.9
Total current regulatory assets	**$ 16.0**	$ 5.9
Non-current		
Benefit obligations regulatory asset	**$359.2**	$365.5
Income taxes recoverable from customers, net	**54.0**	43.3
Smart Grid	**37.2**	14.2
Deferred storm expenses	**23.8**	28.6
Unamortized loss on reacquired debt	**14.2**	15.3
Deferred pension expenses	**9.1**	13.5
Other	**10.4**	9.0
Total non-current regulatory assets	**$507.9**	$489.4
Regulatory Liabilities		
Current		
Smart Grid rider over collections[B]	**$ 24.3**	$ 10.4
Fuel clause over recoveries	**7.7**	29.9
Other[B]	**13.7**	10.5
Total current regulatory liabilities	**$ 45.7**	$ 50.8
Non-Current		
Accrued removal obligations, net	**$208.2**	$184.9
Pension tracker	**22.5**	8.2
Total non-current regulatory liabilities	**$230.7**	$193.1

[A] *Included in Other Current Assets on the Consolidated Balance Sheets.*
[B] *Included in Other Current Liabilities on the Consolidated Balance Sheets.*

Fuel clause under recoveries are generated from under recoveries from OG&E's customers when OG&E's cost of fuel exceeds the amount billed to its customers. Fuel clause over recoveries are generated from over recoveries from OG&E's customers when the amount billed to its customers exceeds OG&E's cost of fuel. OG&E's fuel recovery clauses are designed to smooth the impact of fuel price volatility on customers' bills. As a result, OG&E under recovers fuel costs in periods of rising fuel prices above the baseline charge for fuel and over recovers fuel costs when prices decline below the baseline charge for fuel. Provisions in the fuel clauses are intended to allow OG&E to amortize under and over recovery balances.

The benefit obligations regulatory asset is comprised of expenses recorded which are probable of future recovery and that have not yet been recognized as components of net periodic benefit cost, including net loss, prior service cost and net transition obligation. These expenses were allowed to be recorded as a regulatory asset as OG&E had historically recovered and currently recovers pension and postretirement benefit plan expense in its electric rates and there was no negative evidence that the existing regulatory treatment would change. If, in the future, the regulatory bodies indicate a change in policy related to the recovery of pension and postretirement benefit plan expenses, this could cause the benefit obligations regulatory asset balance to be reclassified to Accumulated Other Comprehensive Income.

The following table is a summary of the components of the benefit obligations regulatory asset at:

(In millions, December 31)	2011	2010
Pension plan and restoration of retirement income plan:		
Net loss	**$266.3**	$215.0
Prior service cost	**7.0**	9.7
Postretirement plans:		
Net loss	**144.2**	135.7
Prior service cost	**(60.8)**	–
Net transition obligation	**2.5**	5.1
Total	**$359.2**	$365.5

The following amounts in the benefit obligations regulatory asset at December 31, 2011 are expected to be recognized as components of net periodic benefit cost in 2012:

(In millions)	
Pension plan and restoration of retirement income plan:	
Net loss	$18.8
Prior service cost	2.5
Postretirement plans:	
Net loss	17.3
Prior service cost	(13.7)
Net transition obligation	2.5
Total	$27.4

Income taxes recoverable from customers, which represents income tax benefits previously used to reduce OG&E's revenues, are treated as regulatory assets and liabilities and are being amortized over the estimated remaining life of the assets to which they relate. These amounts are being recovered in rates as the temporary differences that generated the income tax benefit turn around. The income tax related regulatory assets and liabilities are netted in Income Taxes Recoverable from Customers, Net in the regulatory assets and liabilities table above.

In accordance with the OCC order received by OG&E in July 2010 related to its Smart Grid project, OG&E established a regulatory asset which includes the cost of system-wide deployment of smart grid technology and implementing the smart grid pilot program, the incremental costs for web portal access, education and providing home energy reports and stranded costs associated with OG&E's existing meters. The costs recoverable from Oklahoma customers for system-wide deployment of smart grid technology and implementing the smart grid pilot program are capped at $366.4 million (inclusive of the U.S. Department of Energy grant award amount) subject to an offset for any recovery of those costs from Arkansas customers and are currently being recovered through a rider which will remain in effect until the Smart Grid project costs are included in base rates beginning in 2014. The incremental costs for web portal access, education and home energy reports are capped at $6.9 million and will be recovered in base rates beginning in 2014. The stranded costs associated with OG&E's existing meters which are being replaced by smart meters will accumulate during the Smart Grid deployment and recovery of the stranded costs will be included in future rate cases. OG&E received an order from the APSC in August 2011 related to its Arkansas Smart Grid project. OG&E will recover estimated capital costs of $14 million and associated operation and maintenance costs for deployment of smart grid technology, along with incremental costs for web portal access and education of $0.8 million, through a rider. The rider will become effective when the smart meters are fully deployed in Arkansas, which is expected during the second quarter of 2012, and will remain in effect until new base rates are implemented subsequent to OG&E's next rate case. The APSC also authorized OG&E to record a regulatory asset for stranded costs associated with OG&E's existing meters and to recover the stranded meter regulatory asset in base rates subsequent to OG&E's next rate case.

In accordance with the September 2008 OCC rate order, OG&E was allowed to defer the Oklahoma storm-related operation and maintenance expenses in excess of $2.7 million and will reserve for any Oklahoma storm-related operation and maintenance expenses less than $2.7 million. OG&E will recover the deferred amounts over a five-year period ending in August 2013.

Unamortized loss on reacquired debt is comprised of unamortized debt issuance costs related to the early retirement of OG&E's long-term debt. These amounts are being amortized over the term of the long-term debt which replaced the previous long-term debt. The unamortized loss on reacquired debt is not included in OG&E's rate base and does not otherwise earn a rate of return.

In accordance with the OCC order received by OG&E in December 2005 in its Oklahoma rate case, OG&E was allowed to recover a certain amount of pension plan expenses. These deferred amounts have been recorded as a regulatory asset as OG&E received an order in July 2009 allowing it to begin recovery of $16.8 million of these costs over a four-year period. In accordance with the APSC order received by OG&E in May 2009 in its Arkansas rate case, OG&E was allowed recovery of its 2006 and 2007 pension settlement costs. During the second quarter of 2009, OG&E reduced its pension expense and recorded a regulatory asset for $3.2 million, which is being amortized over a 10-year period, as allowed in the Arkansas rate order. Both the Oklahoma and Arkansas pension plan expenses are reflected in Deferred Pension expenses asset in the regulatory assets and liabilities table above. Also, in accordance with the OCC order received by OG&E in August 2009 in its Oklahoma rate case, OG&E was allowed to recover a certain amount of pension plan expenses. In accordance with the OCC order received by OG&E in September 2011 in its pension tracker modification filing, OG&E was allowed to include postretirement medical expense in its pension tracker. At December 31, 2011, OG&E had $22.5 million of expenses under this level, which have been recorded as Pension tracker regulatory liability in the regulatory assets and liabilities table above.

Accrued removal obligations represent asset retirement costs previously recovered from ratepayers for other than legal obligations.

Management continuously monitors the future recoverability of regulatory assets. When in management's judgment future recovery becomes impaired, the amount of the regulatory asset is adjusted, as appropriate. If the Company were required to discontinue the application of accounting principles for certain types of rate-regulated activities for some or all of its operations, it could result in writing off the related regulatory assets, which could have significant financial effects.

Use of Estimates

In preparing the Consolidated Financial Statements, management is required to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and contingent liabilities at the date of the Consolidated Financial Statements and the reported amounts of revenues and expenses during the reporting period. Changes to these assumptions and estimates could have a material effect on the Company's Consolidated Financial Statements. However, the Company believes it has taken reasonable, but conservative, positions where assumptions and estimates are used in order to minimize the negative financial impact to the Company that could result if actual results vary from the assumptions and estimates. In management's opinion, the areas of the Company where the most significant judgment is exercised for all Company segments includes the valuation of Pension Plan assumptions, impairment estimates of long-lived assets (including intangible assets) and goodwill, income taxes, contingency reserves, asset retirement obligations, fair value and cash flow hedges and the allowance for uncollectible accounts receivable. For the electric utility segment, the most significant judgment is also exercised in the valuation of regulatory assets and liabilities and unbilled revenues. For the natural gas transportation and storage, gathering and processing and marketing segments, the most significant judgment is also exercised in the valuation of operating revenues, natural gas purchases, purchase and sale contracts, assets and depreciable lives of property, plant and equipment and amortization methodologies related to intangible assets.

Cash and Cash Equivalents

For purposes of the Consolidated Financial Statements, the Company considers all highly liquid debt instruments purchased with an original maturity of three months or less to be cash equivalents. These investments are carried at cost, which approximates fair value.

Allowance for Uncollectible Accounts Receivable

For OG&E, customer balances are generally written off if not collected within six months after the final billing date. The allowance for uncollectible accounts receivable for OG&E is calculated by multiplying the last six months of electric revenue by the provision rate. The provision rate is based on a 12-month historical average of actual balances written off. To the extent the historical collection rates are not representative of future collections, there could be an effect on the amount of uncollectible expense recognized. Beginning in August 2009 and going forward, there was a change in the provision calculation as a result of the Oklahoma rate case whereby the portion of the uncollectible provision related to fuel is being recovered through the fuel adjustment clause. Due to the extremely hot weather in OG&E's service territory in 2011, OG&E recorded an additional amount of uncollectible expense anticipating higher customer defaults. The allowance for uncollectible accounts receivable for Enogex is calculated based on outstanding accounts receivable balances over 180 days old. In addition, other outstanding accounts receivable balances less than 180 days old are reserved on a case-by-case basis when Enogex believes the collection of specific amounts owed is unlikely to occur. The allowance for uncollectible accounts receivable was $3.8 million and $1.9 million at December 31, 2011 and 2010, respectively.

For OG&E, new business customers are required to provide a security deposit in the form of cash, bond or irrevocable letter of credit that is refunded when the account is closed. New residential customers, whose outside credit scores indicate risk, are required to provide a security deposit that is refunded based on customer protection rules defined by the OCC and the APSC. The payment behavior of all existing customers is continuously monitored and, if the payment behavior indicates sufficient risk within the meaning of the applicable utility regulation, customers will be required to provide a security deposit.

For Enogex, credit risk is the risk of financial loss to Enogex if counterparties fail to perform their contractual obligations. Enogex maintains credit policies with regard to its counterparties that management believes minimize overall credit risk. These policies include the evaluation of a potential counterparty's financial position (including credit rating, if available), collateral requirements under certain circumstances, the use of standardized agreements which provide for the netting of cash flows associated with a single counterparty and the monitoring of the financial position of existing counterparties on an ongoing basis.

Fuel Inventories

OG&E

Fuel inventories for the generation of electricity consist of coal, natural gas and oil. OG&E uses the weighted-average cost method of accounting for inventory that is physically added to or withdrawn from storage or stockpiles. The amount of fuel inventory was $76.9 million and $134.9 million at December 31, 2011 and 2010, respectively.

Enogex

Natural gas inventory is held by Enogex, through its transportation and storage business to provide operational support for its pipeline deliveries and through its marketing business to manage its leased storage capacity. In an effort to mitigate market price exposures, Enogex may enter into contracts or hedging instruments to protect the cash flows associated with its inventory. All natural gas inventory held by Enogex is valued using moving average cost and is recorded at the lower of cost or market. As part of its recurring marketing activity, OER injects and withdraws natural gas into and out of inventory under the terms of its storage capacity contracts. During the years ended December 31, 2011, 2010 and 2009, Enogex recorded write-downs to market value related to natural gas storage inventory of $4.8 million, $0.3 million and $6.1 million, respectively. The amount of Enogex's natural gas inventory was $23.7 million and $23.9 million at December 31, 2011 and 2010, respectively. The cost of gas associated with sales of natural gas storage inventory is presented in Cost of Goods Sold on the Consolidated Statements of Income.

Gas Imbalances

Gas imbalances occur when the actual amounts of natural gas delivered from or received by Enogex's pipeline system differ from the amounts scheduled to be delivered or received. Imbalances are due to or due from shippers and operators and can be settled in cash or made up in-kind depending on contractual terms. Enogex values all imbalances at an average of current market indices applicable to Enogex's operations, not to exceed net realizable value.

Property, Plant and Equipment

OG&E

All property, plant and equipment is recorded at cost. Newly constructed plant is added to plant balances at cost which includes contracted services, direct labor, materials, overhead, transportation costs and the allowance for funds used during construction. Replacements of units of property are capitalized as plant. For assets that belong to a common plant account, the replaced plant is removed from plant balances and the cost of such property is charged to Accumulated Depreciation. For assets that do not belong to a common plant account, the replaced plant is removed from plant balances with the related accumulated depreciation and the remaining balance net of any salvage proceeds is recorded as a loss in the Consolidated Statements of Income as Other Expense. Repair and replacement of minor items of property are included in the Consolidated Statements of Income as Other Operation and Maintenance Expense.

The table below presents OG&E's ownership interest in the jointly-owned McClain Plant and the jointly-owned Redbud Plant, and, as disclosed below, only OG&E's ownership interest is reflected in the property, plant and equipment and accumulated depreciation balances in these tables. The owners of the remaining interests in the McClain Plant and the Redbud Plant are responsible for providing their own financing of capital expenditures. Also, only OG&E's proportionate interests of any direct expenses of the McClain Plant and the Redbud Plant such as fuel, maintenance expense and other operating expenses are included in the applicable financial statement captions in the Consolidated Statement of Income.

(In millions, December 31)	Percentage Ownership	Total Property, Plant and Equipment	Accumulated Depreciation	Net Property, Plant and Equipment
2011				
McClain Plant	77%	$207.2	$73.7	$133.5
Redbud Plant	51%	$461.1 [A]	$54.3 [B]	$406.8

[A] This amount includes a plant acquisition adjustment of $148.3 million.

[B] This amount includes accumulated amortization of the plant acquisition adjustment of $17.9 million.

Enogex

All property, plant and equipment is recorded at cost. Newly constructed plant is added to plant balances at cost which includes contracted services, direct labor, materials, overhead, transportation costs and capitalized interest. Replacements of units of property are capitalized as plant. For assets that belong to a common plant account, the replaced plant is removed from plant balances and charged to Accumulated Depreciation. For assets that do not belong to a common plant account, the replaced plant is removed from plant balances with the related accumulated depreciation and the remaining balance net of any salvage proceeds is recorded as a loss in the Consolidated Statements of Income as Other Expense. Repair and removal costs are included in the Consolidated Statements of Income as Other Operation and Maintenance Expense.

On December 8, 2010, a fire occurred at Enogex's Cox City natural gas processing plant destroying major components of one of the four processing trains, representing 120 MMcf/d of the total 180 MMcf/d of capacity, at that facility. Gas volumes normally processed at the Cox City plant were diverted to other facilities or bypassed around Enogex's system to accommodate production and all of the impacted gathered volumes were back online in December 2010. The damaged train was replaced and the facility was returned to full service in September 2011. The total cost necessary to return the facility back to full service was $29.6 million. While Enogex believes that the costs in excess of the $10 million deductible should be reimbursed by insurance, the matter is currently being negotiated with the insurance company and Enogex cannot predict the precise outcome of these negotiations or the timing associated with the recovery. In the fourth quarter of 2011, Enogex received a partial insurance reimbursement of $7.4 million and recognized a gain of $3.0 million on insurance proceeds. Enogex expects to receive additional reimbursement of portions of the costs in 2012. Enogex will recognize insurance recoveries in earnings as the insurance claims are resolved.

OGE Energy Consolidated

The Company's property, plant and equipment and related accumulated depreciation are divided into the following major classes at:

(In millions, December 31)	Total Property, Plant and Equipment	Accumulated Depreciation	Net Property, Plant and Equipment
2011			
OGE Energy (holding company)			
Property, plant and equipment	**$ 124.6**	**$ 90.6**	**$ 34.0**
OGE Energy property, plant and equipment	**124.6**	**90.6**	**34.0**
OG&E			
Distribution assets	**2,981.3**	**920.3**	**2,061.0**
Electric generation assets	**3,360.6**	**1,215.8**	**2,144.8**
Transmission assets	**1,464.2**	**339.6**	**1,124.6**
Intangible plant	**43.2**	**20.3**	**22.9**
Other property and equipment	**293.9**	**96.3**	**197.6**
OG&E property, plant and equipment	**8,143.2**	**2,592.3**	**5,550.9**
Enogex			
Transportation and storage assets	**956.9**	**271.0**	**685.9**
Gathering and processing assets	**1,580.1**	**381.0**	**1,199.1**
Marketing assets	**10.1**	**6.0**	**4.1**
Enogex property, plant and equipment	**2,547.1**	**658.0**	**1,889.1**
Total property, plant and equipment	**$10,814.9**	**$3,340.9**	**$7,474.0**
2010			
OGE Energy (holding company)			
Property, plant and equipment	$ 111.1	$ 77.5	$ 33.6
OGE Energy property, plant and equipment	111.1	77.5	33.6
OG&E			
Distribution assets	2,833.4	897.4	1,936.0
Electric generation assets	3,047.1	1,164.6	1,882.5
Transmission assets	1,221.3	325.6	895.7
Intangible plant	26.5	20.7	5.8
Other property and equipment	243.4	86.1	157.3
OG&E property, plant and equipment	7,371.7	2,494.4	4,877.3
Enogex			
Transportation and storage assets	924.7	250.0	674.7
Gathering and processing assets	1,230.8	354.6	876.2
Marketing assets	9.7	7.1	2.6
Enogex property, plant and equipment	2,165.2	611.7	1,553.5
Total property, plant and equipment	$ 9,648.0	$3,183.6	$6,464.4

Depreciation and Amortization

OG&E

The provision for depreciation, which was 2.9 percent and 3.0 percent, respectively, of the average depreciable utility plant for 2011 and 2010, is provided on a straight-line method over the estimated service life of the utility assets. Depreciation is provided at the unit level for production plant and at the account or sub-account level for all other plant, and is based on the average life group method. In 2012, the provision for depreciation is projected to be 2.9 percent of the average depreciable utility plant. Amortization of intangible assets is computed using the straight-line method. Of the remaining amortizable intangible plant balance at December 31, 2011, 48.3 percent will be amortized over three years with 51.7 percent of the remaining amortizable intangible plant balance at December 31, 2011 being amortized over their respective lives ranging from four to 25 years. Amortization of plant acquisition adjustments is provided on a straight-line basis over the estimated remaining service life of the acquired asset. Plant acquisition adjustments include $148.3 million for the Redbud Plant, which are being amortized over a 27-year life and $3.3 million for certain substation facilities in OG&E's service territory, which are being amortized over a 26 to 59-year period.

Enogex

For Enogex, depreciation is computed principally on the straight-line method using estimated useful lives of three to 83 years for transportation and storage assets, three to 30 years for gathering and processing assets and three to 10 years for general plant assets. Amortization of intangible assets other than debt costs is computed using the straight-line method over the respective lives of the intangible assets ranging up to 20 years.

The computation of depreciation expense requires judgment regarding the estimated useful lives and salvage value of assets at the time the assets are placed in service. As circumstances warrant, useful lives are adjusted when changes in planned use, changes in estimated production lives of affiliated natural gas basins or other factors indicate that a different life would be more appropriate. Such changes could materially impact future depreciation expense. Changes in useful lives that do not result in the impairment of an asset are recognized prospectively. The computation of amortization expense on intangible assets requires judgment regarding the amortization method used. The intangible asset should be amortized over its useful life using a method of amortization that reflects the pattern in which the economic benefits of the intangible asset are consumed.

Asset Retirement Obligations

The Company has previously recorded asset retirement obligations that are being amortized over their respective lives ranging from 20 to 99 years. In the fourth quarter of 2011, OG&E recorded an asset retirement obligation for $13.0 million related to its Crossroads wind farm. Beginning December 1, 2011, OG&E began to amortize the value of the related asset retirement obligation asset over the estimated remaining life of 50 years. The Company also has certain asset retirement obligations that have not been recorded because the Company determined that these assets, primarily related to Enogex's processing plants and compression sites and OG&E's power plant sites, have indefinite lives.

Impairment of Long-Lived Assets (Including Intangible Assets) and Goodwill

The Company assesses its long-lived assets, including intangible assets with finite useful lives, for impairment when there is evidence that events or changes in circumstances require an analysis of the recoverability of an asset's carrying amount. Estimates of future cash flows used to test the recoverability of long-lived assets and intangible assets shall include only the future cash flows (cash inflows less associated cash outflows) that are directly associated with and that are expected to arise as a direct result of the use and eventual disposition of the asset. The fair value of these assets is based on third-party evaluations, prices for similar assets, historical data and projected cash flows. An impairment loss is recognized when the sum of the expected future net cash flows is less than the carrying amount of the asset. The amount of any recognized impairment is based on the estimated fair value of the asset subject to impairment compared to the carrying amount of such asset. In 2011, the Company recorded a pre-tax impairment loss of $5.0 million, of which $2.5 million was the noncontrolling interest portion (see Note 5), related to the Atoka processing plant. The Company recorded no other material impairments in 2011, 2010 and 2009.

As a result of the gas gathering acquisitions on November 1, 2011 discussed in Note 3, Enogex recorded goodwill of $39.4 million and intangible assets of $136.3 million. Enogex will assess its goodwill for impairment at least annually as of October 1 and will assess the intangible assets for impairment as discussed above.

Allowance for Funds Used During Construction

For OG&E, allowance for funds used during construction is calculated according to the FERC pronouncements for the imputed cost of equity and borrowed funds. Allowance for funds used during construction, a non-cash item, is reflected as a reduction to interest expense in the Consolidated Statements of Income and as an increase to Construction Work in Progress in the Consolidated Balance Sheets. Allowance for funds used during construction rates, compounded semi-annually, were 8.71 percent, 8.89 percent and 7.99 percent for the years ended December 31, 2011, 2010 and 2009, respectively. The decrease in the allowance for funds used during construction rates in 2011 was primarily due to the issuance of long-term debt which changed the cost of capital weighting to shift towards debt which has a lower effective rate than equity.

Collection of Sales Tax

In the course of its operations, OG&E collects sales tax from its customers. OG&E records a current liability for sales taxes when it bills its customers and eliminates this liability when the taxes are remitted to the appropriate governmental authorities. OG&E excludes the sales tax collected from its operating revenues.

Revenue Recognition

OG&E

General. OG&E reads its customers' meters and sends bills to its customers throughout each month. As a result, there is a significant amount of customers' electricity consumption that has not been billed at the end of each month. Unbilled revenue is presented in Accrued Unbilled Revenues on the Consolidated Balance Sheets and in Operating Revenues on the Consolidated Statements of Income based on estimates of usage and prices during the period. The estimates that management uses in this calculation could vary from the actual amounts to be paid by customers.

SPP Purchases and Sales. OG&E participates in the SPP energy imbalance service market in a dual role as a load serving entity and as a generation owner. The energy imbalance service market requires cash settlements for over or under schedules of generation and load. Market participants, including OG&E, are required to submit resource plans and can submit offer curves for each resource available for dispatch. A function of interchange accounting is to match participants' MWH entitlements (generation plus scheduled bilateral purchases) against their MWH obligations (load plus scheduled bilateral sales) during every hour of every day. If the net result during any given hour is an entitlement, the participant is credited with a spot-market sale to the SPP at the respective market price for that hour; if the net result is an obligation, the participant is charged with a spot-market purchase from the SPP at the respective market price for that hour. The SPP purchases and sales are not allocated to individual customers. OG&E records the hourly sales to the SPP at market rates in Operating Revenues and the hourly purchases from the SPP at market rates in Cost of Goods Sold in its Consolidated Financial Statements.

Enogex

Operating revenues for gathering, processing, transportation, storage and marketing services for Enogex are recorded each month based on the current month's estimated volumes, contracted prices (considering current commodity prices), historical seasonal fluctuations and any known adjustments. The estimates are reversed in the following month and customers are billed on actual volumes and contracted prices. Gas sales are calculated on current-month nominations and contracted prices. Operating revenues associated with the production of NGLs are estimated based on current-month estimated production and contracted prices. These amounts are reversed in the following month and the customers are billed on actual production and contracted prices. Estimated operating revenues are reflected in Accounts Receivable on the Consolidated Balance Sheets and in Operating Revenues on the Consolidated Statements of Income. Enogex's key natural gas producer customers in 2011 included Chesapeake Energy Marketing Inc., Apache Corporation, Devon Energy Production Company, L.P., BP America Production Company and Kaiser Francis Oil Co. In 2011, these five customers accounted for 19.9 percent, 15.0 percent, 12.5 percent, 4.1 percent and 3.9 percent, respectively, of Enogex's gathering and processing volumes. In 2011, Enogex's top 10 natural gas producer customers accounted for 69.4 percent of Enogex's gathering and processing volumes.

Enogex recognizes revenue from natural gas gathering, processing, transportation, storage and marketing services to third parties as services are provided. Revenue associated with NGLs is recognized when the production is sold. Enogex depends on third-party facilities to transport and fractionate NGLs that it delivers to the third party at the tailgates of its processing plants. Additionally, the third party purchases 50 percent of the NGLs delivered to its system, which accounted for $285.4 million (38.8 percent, $279.8 million (46.0 percent) and $170.0 million (49.5 percent), respectively, of Enogex's total NGLs sales for the years ended December 31, 2011, 2010 and 2009. If this third-party's pipeline or other facilities become partially or fully unavailable, Enogex's revenues and cash flows could be adversely affected.

Enogex records deferred revenue when it receives consideration from a third party before achieving certain criteria that must be met for revenue to be recognized in accordance with GAAP.

Enogex, through OER, engages in energy marketing, trading, risk management and hedging activities related to the purchase and sale of natural gas as well as hedging activity related to the sale of natural gas and NGLs on behalf of the Company. Contracts utilized in these activities generally include purchases and sales for physical delivery of natural gas, over-the-counter forward swap and option contracts and exchange traded futures and options. OER's transactions that qualify as derivatives are reflected at fair value with the resulting unrealized gains and losses recorded as PRM Assets or Liabilities in the Consolidated Balance Sheets, classified as current or long-term based on their anticipated settlement, or against the brokerage deposits in Other Current Assets. The offsetting unrealized gains and losses from changes in the market value of open contracts are included in Operating Revenues in the Consolidated Statements of Income or in Other Comprehensive Income for derivatives designated and qualifying as cash flow hedges. Contracts resulting in delivery of a commodity are included as sales or purchases in the Consolidated Statements of Income as Operating Revenues or Cost of Goods Sold depending on whether the contract relates to the sale or purchase of the commodity.

Estimates for gas purchases are based on estimated volumes and contracted purchase prices. Estimated gas purchases are included in Accounts Payable on the Consolidated Balance Sheets and in Cost of Goods Sold on the Consolidated Statements of Income.

Normal purchases and normal sales contracts are not recorded in PRM Assets or Liabilities in the Consolidated Balance Sheets and earnings recognition is recorded in the period in which physical delivery of the commodity occurs. Management applies normal purchases and normal sales treatment to: (i) commodity contracts for the purchase and sale of natural gas used in or produced by Enogex's operations and (ii) commodity contracts for the sale of NGLs produced by Enogex's gathering and processing business.

Fuel Adjustment Clauses

Variances in the actual cost of fuel used in electric generation and certain purchased power costs, as compared to the fuel component in the cost-of-service for ratemaking, are passed through to OG&E's customers through fuel adjustment clauses, which are subject to periodic review by the OCC, the APSC and the FERC.

Income Taxes

The Company files consolidated income tax returns in the U.S. Federal jurisdiction and various state jurisdictions. Income taxes are generally allocated to each company in the affiliated group based on its stand-alone taxable income or loss. Federal investment tax credits previously claimed on electric utility property have been deferred and are being amortized to income over the life of the related property. The Company uses the asset and liability method of accounting for income taxes. Under this method, a deferred tax asset or liability is recognized for the estimated future tax effects attributable to temporary differences between the financial statement basis and the tax basis of assets and liabilities as well as tax credit carry forwards and net operating loss carry forwards. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in the period of the change. The Company recognizes interest related to unrecognized tax benefits in interest expense and recognizes penalties in other expense.

Accrued Vacation

The Company accrues vacation pay monthly by establishing a liability for vacation earned. Vacation may be taken as earned and is charged against the liability. At the end of each year, the liability represents the amount of vacation earned, but not taken.

Accumulated Other Comprehensive Income (Loss)

The following table summarizes the components of accumulated other comprehensive loss at December 31, 2011 and 2010 attributable to OGE Energy. At both December 31, 2011 and 2010, there was no accumulated other comprehensive loss related to Enogex's noncontrolling interest in Atoka.

(In millions, December 31)	2011	2010
Pension plan and restoration of retirement income plan:		
Net loss	**$(42.1)**	$(31.1)
Prior service cost	**(0.1)**	(0.5)
Postretirement plans:		
Net loss	**(15.4)**	(13.6)
Prior service cost	**9.0**	–
Net transition obligation	**(0.1)**	(0.3)
Deferred commodity contracts hedging losses	**3.3**	(19.5)
Deferred interest rate swaps hedging losses	**(0.7)**	(1.0)
Total accumulated other comprehensive loss	**(46.1)**	(66.0)
Less: Accumulated other comprehensive loss attributable to noncontrolling interests	**(5.5)**	(5.8)
Accumulated other comprehensive loss, net of tax	**$(40.6)**	$(60.2)

Of the deferred hedging losses at December 31, 2011, $4.9 million are expected to be recognized into earnings during 2012.

Pension Plan, Restoration of Retirement Income Plan and Postretirement Plans

The amounts in accumulated other comprehensive loss at December 31, 2011 that are expected to be recognized as components of net periodic benefit cost in 2012 are as follows:

(In millions)	
Pension plan and restoration of retirement income plan:	
Net loss	$ 2.7
Prior service cost	0.3
Postretirement plans:	
Net loss	1.9
Prior service cost	(1.8)
Net transition obligation	0.1
Total, net of tax	$ 3.2

Environmental Costs

Accruals for environmental costs are recognized when it is probable that a liability has been incurred and the amount of the liability can be reasonably estimated. Costs are charged to expense or deferred as a regulatory asset based on expected recovery from customers in future rates, if they relate to the remediation of conditions caused by past operations or if they are not expected to mitigate or prevent contamination from future operations. Where environmental expenditures relate to facilities currently in use, such as pollution control equipment, the costs may be capitalized and depreciated over the future service periods. Estimated remediation costs are recorded at undiscounted amounts, independent of any insurance or rate recovery, based on prior experience, assessments and current technology. Accrued obligations are regularly adjusted as environmental assessments and estimates are revised, and remediation efforts proceed. For sites where OG&E or Enogex have been designated as one of several potentially responsible parties, the amount accrued represents OG&E's or Enogex's estimated share of the cost. The Company has less than $0.1 million in accrued environmental liabilities at both December 31, 2011 and 2010.

Reclassifications

Certain prior year amounts have been reclassified on the Consolidated Statements of Income for impairment of assets and on the Consolidated Balance Sheet for intangible assets to conform to the 2011 presentation.

2. Accounting Pronouncements

In December 2011, the Financial Accounting Standards Board issued "Balance Sheet: Disclosures about Offsetting Assets and Liabilities." The new standard requires entities to disclose information about financial instruments and derivative instruments that are either offset on the balance sheet or are subject to a master netting arrangement, including providing both gross information and net information for recognized assets and liabilities, the net amounts presented on an entity's balance sheet and a description of the rights of setoff associated with these assets and liabilities. The new standard is applicable for all entities that have financial instruments and derivative instruments shown using a net presentation on an entity's balance sheet or are subject to a master netting arrangement. The new standard is effective for interim and annual reporting periods for fiscal years beginning on or after January 1, 2013 and should be applied retrospectively for all periods presented. The Company plans to adopt this new standard effective January 1, 2013 and will provide any additional disclosures necessary to comply with the new standard.

In December 2011, the Financial Accounting Standards Board issued "Comprehensive Income: Deferral of the Effective Date for Amendments to the Presentation of Reclassifications of Items Out of Accumulated Other Comprehensive Income in Accounting Standards

Update No. 2011-05." The new standard defers the effective date of changes from previous accounting guidance that related to the presentation of reclassification adjustments. The new standard is applicable for all entities that have other comprehensive income. The new standard is effective for interim and annual reporting periods for fiscal years beginning after December 15, 2011. The Company adopted this new standard effective January 1, 2012.

3. Business Combination

On September 23, 2011, Enogex entered into the following agreements: an agreement with Cordillera, Oxbow and West Canadian Midstream LLC pursuant to which Enogex agreed to acquire 100 percent of the membership interest in Roger Mills Gas Gathering, LLC, an Oklahoma limited liability company that owns an approximately 60-mile natural gas gathering system located in Roger Mills County and Ellis County, Oklahoma; an agreement with Cordillera and Oxbow pursuant to which Enogex agreed to acquire an approximately 30-mile natural gas gathering system located in Roger Mills County, Oklahoma; and agreements with Cordillera and other producers pursuant to which such producers agreed to provide Enogex with long-term acreage dedication in the area served by the gathering systems encompassing approximately 100,000 net acres. The gathering systems are located in the Granite Wash area. The aggregate purchase price for these transactions was $200.4 million which was paid in cash primarily from contributions from OGE Energy and the ArcLight group (as discussed in Note 4) as well as cash generated from operations and bank borrowings. The transactions closed on November 1, 2011.

The acquisition described above was accounted for as a business combination. The purchase price shown below is preliminary and has been allocated to the identifiable assets acquired and liabilities assumed based on the estimated fair values at the acquisition date using a third-party valuation expert. Any amount not allocated to identifiable assets and liabilities was allocated to goodwill. These allocations may change in subsequent financial statements. Enogex is currently evaluating the preliminary purchase price allocation, which will be adjusted as additional information relative to the fair value of assets and liabilities becomes available. Enogex expects the purchase price allocations to be completed by the end of the first quarter of 2012. The following table summarizes the preliminary purchase price allocation for this acquisition.

(In millions)	
Current assets	$ 5.4
Net property, plant and equipment	24.3
Intangible assets	136.3
Goodwill	39.4
Current liabilities assumed	(5.0)
Total	$200.4

The goodwill recognized from this acquisition primarily related to the benefits associated with combining the acquired assets with Enogex's existing assets and operations. Enogex believes that the transactions will provide Enogex with key new opportunities in the Granite Wash area. All of the goodwill is deductible for tax purposes. The goodwill has been recorded in the Gathering and Processing segment. At December 31, 2011, there were no changes in the recognized amount of goodwill resulting from this acquisition.

Intangible assets consist of an identifiable customer contracts and relationships. The acquired intangible assets will be amortized on a straight-line basis over the estimated remaining useful life of 15 years. The net amount of intangible assets and related accumulated amortization was $134.8 million and $1.5 million, respectively, at December 31, 2011.

4. Noncontrolling Interest Owner

In 2011, OGE Energy and the ArcLight group made contributions to Enogex Holdings of $70.9 million and $214.6 million, respectively, to fund a portion of Enogex LLC's 2011 capital requirements. Also, on February 1, 2011, OGE Energy sold a 0.1 percent membership interest in Enogex Holdings to the ArcLight group for $1.9 million. The following table summarizes changes in OGE Holdings' and the ArcLight group's membership interest in Enogex Holdings in 2011.

(In millions)	OGE Holdings	ArcLight Group	Total
Balance at December 31, 2010 (units)	90.1	9.9	100.0
Ownership percentage at December 31, 2010	90.1%	9.9%	100.0%
Sale of 100,000 units of Enogex Holdings[(A)]	(0.1)	0.1	–
Issuance of 4,303,007 units of Enogex Holdings[(B)]	0.4	3.9	4.3
Issuance of 5,405,405 units of Enogex Holdings[(C)]	0.5	4.9	5.4
Issuance of 5,725,190 units of Enogex Holdings[(D)]	2.9	2.8	5.7
Balance at December 31, 2011 (units)	93.8	21.6	115.4
Ownership percentage at December 31, 2011	81.3%	18.7%	100.0%

(A) *On February 1, 2011, OGE Energy sold a 0.1 percent membership interest in Enogex Holdings to the ArcLight group for $1.9 million.*
(B) *On February 1, 2011, OGE Energy and the ArcLight group made contributions of $8.0 million and $71.6 million, respectively, to fund a portion of Enogex LLC's 2011 capital requirements.*
(C) *On October 3, 2011, OGE Energy and the ArcLight group made contributions of $10.0 million and $90.0 million, respectively, to fund a portion of Enogex LLC's 2011 capital requirements.*
(D) *On November 1, 2011, OGE Energy and the ArcLight group made contributions of $52.9 million and $53.0 million, respectively, to fund Enogex's gas gathering acquisitions as discussed in Note 3.*

The following table summarizes changes in OGE Energy's equity which represents changes in additional paid-in capital for unrecognized gains from the sale and issuance of equity interests in Enogex Holdings to the ArcLight group in 2011.

(In millions)	
Net income attributable to OGE Energy	$342.9
Transfers to the noncontrolling interest	
Increase in paid-in capital for sale of 100,000 units of Enogex Holdings (net of tax of $0.3 million)	0.5
Increase in paid-in capital for issuance of 4,303,007 units of Enogex Holdings (net of tax of $10.9 million)	17.3
Increase in paid-in capital for issuance of 5,405,405 units of Enogex Holdings (net of tax of $12.3 million)	19.5
Increase in paid-in capital for issuance of 5,725,190 units of Enogex Holdings (net of tax of $5.2 million)	8.2
Net transfers to the noncontrolling interest	45.5
Total of net income attributable to OGE Energy and transfers to noncontrolling interest	$388.4

The following table summarizes the quarterly distributions by Enogex Holdings to its partners in 2011.

(In millions)	OGE Holdings Portion	ArcLight Group's Portion	Total Distribution
First quarter 2011	$ 7.5	$ 0.8	$ 8.3
Second quarter 2011	34.3	5.3	39.6
Third quarter 2011	43.4	6.6	50.0
Fourth quarter 2011	30.4	4.7	35.1
Total	$115.6	$17.4	$133.0

5. Impairment of Assets

Atoka operated a 20 MMcf/d refrigeration processing plant which processed gas gathered in the Atoka area. The processing plant was leased on a month-to-month basis. In August 2011, management made a decision to use third-party processing exclusively for gathered volumes dedicated to Atoka and, therefore, to take the processing plant out of service and return it to the lessor in accordance with the rental agreement. As a result, in August 2011 Enogex recorded a pre-tax impairment loss of $5.0 million in the Gathering and Processing segment associated with the cost it had capitalized in connection with the installation of the leased plant as it will not be able to recover the remaining value of the assets through future cash flows. The Atoka plant assets were measured at fair value on a nonrecurring basis and are considered level 3 in the fair value hierarchy (see Note 6). The noncontrolling interest portion of the pre-tax impairment loss was $2.5 million which is included in Net Income Attributable to Noncontrolling Interests in the Company's Consolidated Statement of Income.

6. Fair Value Measurements

The classification of the Company's fair value measurements requires judgment regarding the degree to which market data are observable or corroborated by observable market data. GAAP establishes a fair value hierarchy that prioritizes the inputs used to measure fair value based on observable and unobservable data. The hierarchy categorizes the inputs into three levels, with the highest priority given to quoted prices in active markets for identical unrestricted assets or liabilities (Level 1) and the lowest priority given to unobservable inputs (Level 3). Financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. The three levels defined in the fair value hierarchy and examples of each are as follows:

Level 1 inputs are quoted prices in active markets for identical unrestricted assets or liabilities that are accessible at the measurement date. Instruments classified as Level 1 include natural gas futures, swaps and option transactions for contracts traded on the New York Mercantile Exchange ("NYMEX") and settled through a NYMEX clearing broker.

Level 2 inputs are inputs other than quoted prices in active markets included within Level 1 that are either directly or indirectly observable at the reporting date for the asset or liability for substantially the full term of the asset or liability. Level 2 inputs include quoted prices for similar assets or liabilities in active markets and quoted prices for identical or similar assets or liabilities in markets that are not active. Instruments classified as Level 2 include over-the-counter NYMEX natural gas swaps, natural gas basis swaps and natural gas purchase and sales transactions in markets such that the pricing is closely related to the NYMEX pricing.

Level 3 inputs are prices or valuation techniques for the asset or liability that require inputs that are both significant to the fair value measurement and unobservable (i.e., supported by little or no market activity). Unobservable inputs reflect the reporting entity's own assumptions about the assumptions that market participants would use in pricing the asset or liability (including assumptions about risk). Instruments classified as Level 3 include the revaluation of the Atoka plant assets (see Note 5).

The Company utilizes the market approach in determining the fair value of its derivative positions by using either NYMEX published market prices, independent broker pricing data or broker/dealer valuations. The valuations of derivatives with pricing based on NYMEX published market prices may be considered Level 1 if they are settled through a NYMEX clearing broker account with daily margining. Over-the-counter derivatives with NYMEX based prices are considered Level 2 due to the impact of counterparty credit risk. Valuations based on independent broker pricing or broker/dealer valuations may be classified as Level 2 only to the extent they may be validated by an additional source of independent market data for an identical or closely related active market. In certain less liquid markets or for longer-term contracts, forward prices are not as readily available. In these circumstances, contracts are valued using internally developed methodologies that consider historical relationships among various quoted prices in active markets that result in management's best estimate of fair value. These contracts are classified as Level 3.

The impact to the fair value of derivatives due to credit risk is calculated using the probability of default based on Standard & Poor's Ratings Services and/or internally generated ratings. The fair value of derivative assets is adjusted for credit risk. The fair value of derivative liabilities is adjusted for credit risk only if the impact is deemed material.

Contracts with Master Netting Arrangements

Fair value amounts recognized for forward, interest rate swap, option and other conditional or exchange contracts executed with the same counterparty under a master netting arrangement may be offset. The reporting entity's choice to offset or not must be applied consistently. A master netting arrangement exists if the reporting entity has multiple contracts, whether for the same type of conditional or exchange contract or for different types of contracts, with a single counterparty that are subject to a contractual agreement that provides for the net settlement of all contracts through a single payment in a single currency in the event of default on or termination of any one contract. Offsetting the fair values recognized for forward, interest rate swap, option and other conditional or exchange contracts outstanding with a single counterparty results in the net fair value of the transactions being reported as an asset or a liability in the Consolidated Balance Sheets. The Company has presented the fair values of its derivative contracts under master netting agreements using a net fair value presentation.

The following tables summarize the Company's assets and liabilities that are measured at fair value on a recurring basis at December 31, 2011 and 2010 as well as reconcile the Company's commodity contracts fair value to PRM Assets and Liabilities on the Company's Consolidated Balance Sheets at December 31, 2011 and 2010. There were no Level 3 investments held at December 31, 2011.

	Commodity Contracts		Gas Imbalances[(A)]	
(In millions, December 31)	Assets	Liabilities	Assets	Liabilities[(B)]
2011				
Quoted market prices in active market for identical assets (Level 1)	**$ 57.1**	**$ 52.3**	**$ –**	**$ –**
Significant other observable inputs (Level 2)	**4.2**	**1.2**	**1.8**	**7.8**
Total fair value	**61.3**	**53.5**	**1.8**	**7.8**
Netting adjustments	**(57.5)**	**(53.0)**	**–**	**–**
Total	**$ 3.8**	**$ 0.5**	**$1.8**	**$7.8**
2010				
Quoted market prices in active market for identical assets (Level 1)	$ 20.6	$ 20.2	$ –	$ –
Significant other observable inputs (Level 2)	2.7	30.7	2.5	2.8
Significant unobservable inputs (Level 3)	13.3	–	–	–
Total fair value	36.6	50.9	2.5	2.8
Netting adjustments	(34.4)	(34.1)	–	–
Total	$ 2.2	$ 16.8	$2.5	$2.8

(A) The Company uses the market approach to fair value its gas imbalance assets and liabilities, using an average of the Inside FERC Gas Market Report for Panhandle Eastern Pipe Line Co. (Texas, Oklahoma Mainline), ONEOK (Oklahoma) and ANR Pipeline (Oklahoma) indices.

(B) Gas imbalance liabilities exclude fuel reserves for over retained fuel due to shippers of $2.0 million and $3.9 million at December 31, 2011 and 2010, respectively, which fuel reserves are based on the value of natural gas at the time the imbalance was created and which are not subject to revaluation at fair market value.

The following table summarizes the Company's assets and liabilities that are measured at fair value on a recurring basis using significant unobservable inputs (Level 3).

	Commodity Contracts			
	Assets		Liabilities	
(In millions)	**2011**	2010	**2011**	2010
Balance at January 1	**$13.3**	$ 49.0	**$ –**	$ 14.7
Total gains or losses				
Included in other comprehensive income	**(5.4)**	(10.0)	**–**	–
Settlements	**(7.9)**	(25.7)	**–**	(14.7)
Balance at December 31	**$ –**	$ 13.3	**$ –**	$ –

In the fourth quarter of 2011, OG&E recorded an asset retirement obligation for $13.0 million related to its Crossroads wind farm, which is measured at fair value on a nonrecurring basis and is considered level 3 in the fair value hierarchy. The inputs used in the valuation of the asset retirement obligation include the term of the Crossroads lease agreement, the average inflation rate, market risk premium and the credit-adjusted risk free interest rate. The term of the asset retirement obligation of 50 years was determined by the Crossroads lease agreement which states that OG&E will remove the wind turbines and related facilities at the time the lease expires. The inflation rate is calculated by using a 20-year average of the Consumer Price Index. The market risk premium is based on historical market returns relative to the U.S. Treasury rate. The credit-adjusted risk free interest rate is estimated from recent yields of OG&E's outstanding debt.

The following table summarizes the fair value and carrying amount of the Company's financial instruments, including derivative contracts related to the Company's PRM activities, at:

	2011		2010	
(In millions, December 31)	**Carrying Amount**	**Fair Value**	Carrying Amount	Fair Value
Price risk management assets				
Energy derivative contracts	**$ 3.8**	**$ 3.8**	$ 2.2	$ 2.2
Price risk management liabilities				
Energy derivative contracts	**$ 0.5**	**$ 0.5**	$ 16.8	$ 16.8
Long-term debt				
OG&E senior notes	**$1,903.8**	**$2,383.8**	$1,655.0	$1,831.5
OGE Energy senior notes	**99.8**	**108.5**	99.7	106.4
OG&E industrial authority bonds	**135.4**	**135.4**	135.4	135.4
Enogex LLC senior notes	**448.1**	**497.9**	447.8	480.7
Enogex LLC revolving credit agreement	**150.0**	**150.0**	25.0	25.0

The carrying value of the financial instruments on the Consolidated Balance Sheets not otherwise discussed above approximates fair value except for long-term debt which is valued at the carrying amount. The valuation of the Company's energy derivative contracts was determined generally based on quoted market prices. However, in certain instances where market quotes are not available, other valuation techniques or models are used to estimate market values. The valuation of instruments also considers the credit risk of the counterparties. The fair value of the Company's long-term debt is based on quoted market prices and estimates of current rates available for similar issues with similar maturities.

7. Derivative Instruments and Hedging Activities

The Company is exposed to certain risks relating to its ongoing business operations. The primary risks managed using derivatives instruments are commodity price risk and interest rate risk. The Company is also exposed to credit risk in its business operations.

Commodity Price Risk

The Company primarily uses forward physical contracts, commodity price swap contracts and commodity price option features to manage the Company's commodity price risk exposures. Commodity derivative instruments used by the Company are as follows:

- NGLs put options and NGLs swaps are used to manage Enogex's NGLs exposure associated with its processing agreements;
- Natural gas swaps are used to manage Enogex's keep-whole natural gas exposure associated with its processing operations and Enogex's natural gas exposure associated with operating its gathering, transportation and storage assets;
- Natural gas futures and swaps and natural gas commodity purchases and sales are used to manage OER's natural gas exposure associated with its storage and transportation contracts; and
- Natural gas futures and swaps, natural gas options and natural gas commodity purchases and sales are used to manage OER's marketing and trading activities.

Normal purchases and normal sales contracts are not recorded in PRM Assets or Liabilities in the Consolidated Balance Sheets and earnings recognition is recorded in the period in which physical delivery of the commodity occurs. Management applies normal purchases and normal sales treatment to: (i) commodity contracts for the purchase and sale of natural gas used in or produced by Enogex's operations, (ii) commodity contracts for the sale of NGLs produced by Enogex's gathering and processing business, (iii) electric power contracts by OG&E and (iv) fuel procurement by OG&E.

The Company recognizes its non-exchange traded derivative instruments as PRM Assets or Liabilities in the Consolidated Balance Sheets at fair value with such amounts classified as current or long-term based on their anticipated settlement. Exchange traded transactions are settled on a net basis daily through margin accounts with a clearing broker and, therefore, are recorded at fair value on a net basis in Other Current Assets in the Consolidated Balance Sheets.

Interest Rate Risk

The Company's exposure to changes in interest rates primarily relates to short-term variable-rate debt and commercial paper. The Company manages its interest rate exposure by monitoring and limiting the effects of market changes in interest rates. The Company utilizes interest rate derivatives to alter interest rate exposure in an attempt to reduce the effects of these changes. Interest rate derivatives are used solely to modify interest rate exposure and not to modify the overall leverage of the debt portfolio.

Credit Risk

The Company is exposed to certain credit risks relating to its ongoing business operations. Credit risk includes the risk that counterparties that owe the Company money or energy will breach their obligations. If the counterparties to these arrangements fail to perform, the Company may be forced to enter into alternative arrangements. In that event, the Company's financial results could be adversely affected and the Company could incur losses.

Cash Flow Hedges

For derivatives that are designated and qualify as a cash flow hedge, the effective portion of the change in fair value of the derivative instrument is reported as a component of Accumulated Other Comprehensive Income and recognized into earnings in the same period during which the hedged transaction affects earnings. The ineffective portion of a derivative's change in fair value or hedge components excluded from the assessment of effectiveness is recognized currently in earnings. The Company measures the ineffectiveness of commodity cash flow hedges using the change in fair value method whereby the change in the expected future cash flows designated as the hedge transaction are compared to the change in fair value of the hedging instrument. Forecasted transactions, which are designated as the hedged transaction in a cash flow hedge, are regularly evaluated to assess whether they continue to be probable of occurring. If the forecasted transactions are no longer probable of occurring, hedge accounting will cease on a prospective basis and all future changes in the fair value of the derivative will be recognized directly in earnings.

The Company designates as cash flow hedges derivatives used to manage commodity price risk exposure for Enogex's NGLs volumes and corresponding keep-whole natural gas resulting from its natural gas processing contracts (processing hedges) and natural gas positions resulting from its natural gas gathering and processing, pipeline and storage operations (operational gas hedges). The Company also designates as cash flow hedges certain derivatives used to manage natural gas commodity exposure for certain natural gas storage inventory positions. Enogex's cash flow hedges at December 31, 2011 mature by the end of the first quarter of 2012.

Fair Value Hedges

For derivative instruments that are designated and qualify as a fair value hedge, the gain or loss on the derivative as well as the offsetting loss or gain on the hedged item attributable to the hedge risk are recognized currently in earnings. The Company includes the gain or loss on the hedged items in Operating Revenues as the offsetting loss or gain on the related hedging derivative.

At December 31, 2011 and 2010, the Company had no derivative instruments that were designated as fair value hedges.

Derivatives Not Designated As Hedging Instruments

Derivative instruments not designated as hedging instruments are utilized in OER's asset management, marketing and trading activities. For derivative instruments not designated as hedging instruments, the gain or loss on the derivative is recognized currently in earnings.

Quantitative Disclosures Related to Derivative Instruments

At December 31, 2011, the Company had the following derivative instruments that were designated as cash flow hedges.

(In millions)	2011
Gross Notional Volume[(A)]	
Enogex marketing hedges	
Natural gas sales	3.2

(A) *Natural gas in MMBtu's.*

At December 31, 2011, the Company had the following derivative instruments that were not designated as hedging instruments.

(In millions)	Purchases	Sales
Gross Notional Volume[(A)]		
Natural gas[(B)]		
Physical[(C)(D)]	14.3	51.8
Fixed Swaps/Futures	57.9	58.2
Options	17.6	12.8
Basis Swaps	8.2	7.5

(A) *Natural gas in MMBtu's.*

(B) *88.0 percent of the natural gas contracts have durations of one year or less, 5.5 percent have durations of more than one year and less than two years and 6.5 percent have durations of more than two years.*

(C) *Of the natural gas physical purchases and sales volumes not designated as hedges, the majority are priced based on a monthly or daily index and the fair value is subject to little or no market price risk.*

(D) *Natural gas physical sales volumes exceed natural gas physical purchase volumes due to the marketing of natural gas volumes purchased via Enogex's processing contracts, which are not derivative instruments and are excluded from the table above.*

Balance Sheet Presentation Related to Derivative Instruments

The fair value of the derivative instruments that are presented in the Company's Consolidated Balance Sheet at December 31, 2011 are as follows:

		Fair Value	
(In millions) Instrument	Balance Sheet Location	Assets	Liabilities
Derivatives designated as hedging instruments			
Natural gas			
Financial futures/swaps	Other Current Assets	$ 5.2	$ 0.3
Total		$ 5.2	$ 0.3
Derivatives not designated as hedging instruments			
Natural gas			
Financial futures/swaps	Current PRM	$ 0.4	$ –
	Other Current Assets	49.9	49.9
Physical purchases/sales	Current PRM	3.1	0.4
	Non-Current PRM	0.3	0.1
Financial options	Other Current Assets	2.4	2.8
Total		$56.1	$53.2
Total gross derivatives[(A)]		$61.3	$53.5

(A) *See Note 6 for a reconciliation of the Company's total derivatives fair value to the Company's Consolidated Balance Sheet at December 31, 2011.*

The fair value of the derivative instruments that are presented in the Company's Consolidated Balance Sheet at December 31, 2010 are as follows:

		Fair Value	
(In millions) Instrument	Balance Sheet Location	Assets	Liabilities
Derivatives designated as hedging instruments			
NGLs			
Financial options	Current PRM	$13.3	$ –
Natural gas			
Financial futures/swaps	Current PRM	–	28.8
	Other Current Assets	0.6	0.3
Total		$13.9	$29.1
Derivatives not designated as hedging instruments			
Natural gas			
Financial futures/swaps	Current PRM	$ –	$ 0.1
	Other Current Assets	20.0	19.8
Physical purchases/sales	Current PRM	1.4	1.2
	Non-Current PRM	0.8	–
Financial options	Other Current Assets	0.5	0.7
Total		$22.7	$21.8
Total gross derivatives[(A)]		$36.6	$50.9

(A) *See Note 6 for a reconciliation of the Company's total derivatives fair value to the Company's Consolidated Balance Sheet at December 31, 2010.*

Income Statement Presentation Related to Derivative Instruments

The following tables present the effect of derivative instruments on the Company's Consolidated Statement of Income in 2011.

(In millions)	Amount Recognized in Other Comprehensive Income [(A)]	Amount Reclassified from Accumulated Other Comprehensive Income into Income	Amount Recognized in Income
Derivatives in cash flow hedging relationships			
NGLs financial options	$(8.4)	$ (9.8)	$ –
Natural gas financial futures/swaps	2.9	(30.4)	–
Total	$(5.5)	$(40.2)	$ –

(A) The estimated net amount of gains or losses included in Accumulated Other Comprehensive Income at December 31, 2011 that is expected to be reclassified into income within the next 12 months is a loss of $4.9 million.

(In millions)	Amount Recognized in Income
Derivatives not designated as hedging instruments	
Natural gas physical purchases/sales	$(10.0)
Natural gas financial futures/swaps	0.4
Total	$ (9.6)

The following tables present the effect of derivative instruments on the Company's Consolidated Statement of Income in 2010.

(In millions)	Amount Recognized in Other Comprehensive Income	Amount Reclassified from Accumulated Other Comprehensive Income into Income	Amount Recognized in Income
Derivatives in cash flow hedging relationships			
NGLs financial options	$ (9.7)	$ 1.2	$ –
NGLs financial futures/swaps	1.7	(3.7)	–
Natural gas financial futures/swaps	(14.9	(25.9)	0.2
Total	$(22.9)	$(28.4)	$0.2

(In millions)	Amount Recognized in Income
Derivatives not designated as hedging instruments	
Natural gas physical purchases/sales	$(11.7)
Natural gas financial futures/swaps	3.2
Total	$ (8.5)

The following tables present the effect of derivative instruments on the Company's Consolidated Statement of Income in 2009.

(In millions)	Amount Recognized in Other Comprehensive Income	Amount Reclassified from Accumulated Other Comprehensive Income into Income	Amount Recognized in Income
Derivatives in cash flow hedging relationships			
NGLs financial options	$ (56.4)	$ 1.7	$ –
NGLs financial futures/swaps	(33.7)	12.6	–
Natural gas financial futures/swaps	(19.8)	(26.5)	(0.2)
Total	$(109.9)	$(12.2)	$(0.2)

(In millions)	Amount Recognized in Income
Derivatives not designated as hedging instruments	
Natural gas physical purchases/sales	$(24.3)
Natural gas financial futures/swaps	17.7
NGLs financial futures/swaps	(0.2)
Total	$ (6.8)

For derivatives designated as cash flow hedges in the tables above, amounts reclassified from Accumulated Other Comprehensive Income into income (effective portion) and amounts recognized in income (ineffective portion) for the years ended December 31, 2011, 2010 and 2009, if any, are reported in Operating Revenues. For derivatives not designated as hedges in the tables above, amounts recognized in income for the years ended December 31, 2011, 2010 and 2009, if any, are reported in Operating Revenues.

Credit-Risk Related Contingent Features in Derivative Instruments

In the event Moody's Investors Services or Standard & Poor's Ratings Services were to lower the Company's senior unsecured debt rating to a below investment grade rating, at December 31, 2011, the Company would have been required to post $2.1 million of cash collateral to satisfy its obligation under its financial and physical contracts relating to derivative instruments that are in a net liability position at December 31, 2011. In addition, the Company could be required to provide additional credit assurances in future dealings with third parties, which could include letters of credit or cash collateral.

8. Stock-Based Compensation

In 2008, the Company adopted, and its shareowners approved, the 2008 Stock Incentive Plan. Under the 2008 Stock Incentive Plan, restricted stock, stock options, stock appreciation rights and performance units may be granted to officers, directors and other key employees of the Company and its subsidiaries. The Company has authorized the issuance of up to 2,750,000 shares under the 2008 Stock Incentive Plan.

The following table summarizes the Company's pre-tax compensation expense and related income tax benefit for the years ended December 31, 2011, 2010 and 2009 related to the Company's performance units and restricted stock.

(In millions, year ended December 31)	**2011**	2010	2009
Performance units			
Total shareholder return	**$ 8.2**	$ 6.8	$4.4
Earnings per share	**5.5**	2.5	1.4
Total performance units	**13.7**	9.3	5.8
Restricted stock	**1.0**	0.9	0.9
Total compensation expense	**$14.7**	$10.2	$6.7
Income tax benefit	**$ 5.7**	$ 3.9	$2.7

The Company has issued new shares to satisfy stock option exercises, restricted stock grants and payouts of earned performance units. In 2011, 2010 and 2009, there were 311,623 shares, 230,233 shares and 324,651 shares, respectively, of new common stock issued pursuant to the Company's stock incentive plans related to exercised stock options, restricted stock grants and payouts of earned performance units. In 2011, there were 9,258 shares of restricted stock returned to the Company to satisfy tax liabilities.

In November 2011, the Company purchased 120,000 shares of its common stock at an average cost of $51.33 per share on the open market. These shares will be used to satisfy Enogex's portion of the Company's obligation to deliver shares of common stock related to long-term incentive payouts of earned performance units in 2012. The Company expects to purchase shares in the future to satisfy a portion of its obligation under its incentive plan. The Company records treasury stock purchases at cost. Treasury stock is presented as a reduction of stockholders' equity in the Company's Consolidated Balance Sheet.

Performance Units

Under the 2008 Stock Incentive Plan, the Company has issued performance units which represent the value of one share of the Company's common stock. The performance units provide for accelerated vesting if there is a change in control (as defined in the 2008 Stock Incentive Plan). Each performance unit is subject to forfeiture if the recipient terminates employment with the Company or a subsidiary prior to the end of the three-year award cycle for any reason other than death, disability or retirement. In the event of death, disability or retirement, a participant will receive a prorated payment based on such participant's number of full months of service during the award cycle, further adjusted based on the achievement of the performance goals during the award cycle.

The performance units granted based on total shareholder return are contingently awarded and will be payable in shares of the Company's common stock subject to the condition that the number of performance units, if any, earned by the employees upon the expiration of a three-year award cycle (i.e., three-year cliff vesting period) is dependent on the Company's total shareholder return ranking relative to a peer group of companies. The performance units granted based on earnings per share are contingently awarded and will be payable in shares of the Company's common stock based on the Company's earnings per share growth over a three-year award cycle (i.e., three-year cliff vesting period) compared to a target set at the time of the grant by the Compensation Committee of the Company's Board of Directors. All of the Company's performance units are classified as equity in the Consolidated Balance Sheet. If there is no or only a partial payout for the performance units at the end of the award cycle, the unearned performance units are cancelled. Payout requires approval of the Compensation Committee of the Company's Board of Directors. Payouts, if any, are all made in common stock and are considered made when the payout is approved by the Compensation Committee.

Performance Units – Total Shareholder Return

The fair value of the performance units based on total shareholder return was estimated on the grant date using a lattice-based valuation model that factors in information, including the expected dividend yield, expected price volatility, risk-free interest rate and the probable outcome of the market condition, over the expected life of the performance units. Compensation expense for the performance units is a fixed amount determined at the grant date fair value and is recognized over the three-year award cycle regardless of whether performance units are awarded at the end of the award cycle. Dividends are not accrued or paid during the performance period and, therefore, are not included in the fair value calculation. Expected price volatility is based on the historical volatility of the Company's common stock for the past three years and was simulated using the Geometric Brownian Motion process. The risk-free interest rate for the performance unit grants is based on the three-year U.S. Treasury yield curve in effect at the time of the grant. The expected life of the units is based on the non-vested period since inception of the award cycle. There are no post-vesting restrictions related to the Company's performance units based on total shareholder return.

The number of performance units granted based on total shareholder return and the assumptions used to calculate the grant date fair value of the performance units based on total shareholder return are shown in the following table.

	2011	2010	2009
Number of units granted	**213,721**	214,750	316,513
Fair value of units granted	**$ 46.09**	$ 39.43	$ 25.55
Expected dividend yield	**3.2%**	3.9%	4.5%
Expected price volatility	**33.0%**	34.0%	31.0%
Risk-free interest rate	**1.40%**	1.42%	1.25%
Expected life of units (in years)	**2.87**	2.87	2.88

Performance Units – Earnings Per Share

The fair value of the performance units based on earnings per share is based on grant date fair value which is equivalent to the price of one share of the Company's common stock on the date of grant. The fair value of performance units based on earnings per share varies as the number of performance units that will vest is based on the grant date fair value of the units and the probable outcome of the performance condition. The Company reassesses at each reporting date whether achievement of the performance condition is probable and accrues compensation expense if and when achievement of the performance condition is probable. As a result, the compensation expense recognized for these performance units can vary from period to period. There are no post-vesting restrictions related to the Company's performance units based on earnings per share. The number of performance units granted based on earnings per share and the grant date fair value are shown in the following table.

	2011	2010	2009
Number of units granted	**71,238**	71,585	105,504
Fair value of units granted	**$ 41.61**	$ 32.44	$ 20.02

Restricted Stock

Under the 2008 Stock Incentive Plan and beginning in 2008, the Company issued restricted stock to certain existing non-officer employees as well as other executives upon hire to attract and retain individuals to be competitive in the marketplace. The restricted stock vests in one-third annual increments. Prior to vesting, each share of restricted stock is subject to forfeiture if the recipient ceases to render substantial services to the Company or a subsidiary for any reason other than death, disability or retirement. These shares may not be sold, assigned, transferred or pledged and are subject to a risk of forfeiture.

The fair value of the restricted stock was based on the closing market price of the Company's common stock on the grant date. Compensation expense for the restricted stock is a fixed amount determined at the grant date fair value and is recognized as services are rendered by employees over a three-year vesting period. Also, the Company treats its restricted stock as multiple separate awards by recording compensation expense separately for each tranche whereby a substantial portion of the expense is recognized in the earlier years in the requisite service period. Dividends are accrued and paid during the vesting period and, therefore, are included in the fair value calculation. The expected life of the restricted stock is based on the non-vested period since inception of the three-year award cycle. There are no post-vesting restrictions related to the Company's restricted stock. The number of shares of restricted stock granted and the grant date fair value are shown in the following table.

	2011	2010	2009
Shares of restricted stock granted	**17,902**	26,653	6,226
Fair value of restricted stock granted	**$ 48.82**	$ 40.78	$33.38

A summary of the activity for the Company's non-vested performance units and restricted stock at December 31, 2011 and changes in 2011 are shown in the following table.

	Performance Units					
	Total Shareholder Return		Earnings Per Share		Restricted Stock	
	Number of Units	Weighted-Average Grant Date Fair Value	Number of Units	Weighted-Average Grant Date Fair Value	Number of Shares	Weighted-Average Grant Date Fair Value
Units/shares non-vested at 12/31/10	507,154	$31.40	169,054	$25.26	47,739	$36.46
Granted	213,721 (A)	$46.09	71,238 (A)	$41.61	17,902	$48.82
Vested	(291,294)	$25.55	(97,099)	$20.02	(28,397)	$34.05
Forfeited	(14,751)	$40.53	(4,916)	$34.91	–	$ –
Units/shares non-vested at 12/31/11	414,830	$42.75	138,277	$37.01	37,244	$44.24
Units/shares expected to vest	357,974		119,325		37,244	

(A) *Represents target number of units granted. Actual number of units earned, if any, is dependent upon performance and may range from 0 percent to 200 percent of the target.*

Fair Value of Vested Performance Units and Restricted Stock

A summary of the Company's fair value for its vested performance units and restricted stock is shown in the following table.

(In millions, year ended December 31)	2011	2010	2009
Performance units			
Total shareholder return	**$7.4**	$5.4	$1.9
Earnings per share	**3.9**	1.9	0.5
Restricted stock	**1.0**	0.6	0.6

Unrecognized Compensation Cost

A summary of the Company's unrecognized compensation cost for its non-vested performance units and restricted stock and the weighted-average periods over which the compensation cost is expected to be recognized are shown in the following table.

(In millions, December 31)	Unrecognized Compensation Cost	Weighted Average to be Recognized (in years)
Performance units		
Total shareholder return	$ 7.8	1.70
Earnings per share	3.0	1.56
Total performance units	10.8	
Restricted stock	0.9	2.33
Total	$11.7	

Stock Options

The Company last issued stock options in 2004 and as of December 31, 2006, all stock options were fully vested and expensed. All stock options have a contractual life of 10 years. A summary of the activity for the Company's stock options at December 31, 2011 and changes in 2011 are shown in the following table.

(In millions)	Number of Options	Weighted-Average Exercise Price	Aggregate Intrinsic Value	Weighted-Average Remaining Contractual Term
Options outstanding at 12/31/10	100,344	$22.19		
Exercised	(44,544)	$20.94	$2.2	
Options outstanding at 12/31/11	55,800	$23.19	$1.9	1.96 years
Options fully vested and exercisable at 12/31/11	55,800	$23.19	$1.9	1.96 years

A summary of the activity for the Company's exercised stock options in 2011, 2010 and 2009 are shown in the following table.

(In millions, year ended December 31)	2011	2010	2009
Intrinsic value[A]	**$2.2**	$2.5	$1.7
Cash received from stock options exercised	**1.3**	3.2	3.5
Income tax benefit realized for the tax deductions from exercised stock options[B]	**–**	1.0	0.7

(A) The difference between the market value on the date of exercise and the option exercise price.
(B) The Company did not realize an income tax benefit for the tax deductions from the exercised stock options in 2011 due to the Company being in a tax net operating loss position in 2011.

9. Supplemental Cash Flow Information

The following table discloses information about investing and financing activities that affected recognized assets and liabilities but which did not result in cash receipts or payments. Also disclosed in the table is cash paid for interest, net of interest capitalized, and cash paid for income taxes, net of income tax refunds.

(In millions, year ended December 31)	2011	2010	2009
Non-cash investing and financing activities			
Power plant long-term service agreement	**$ 1.7**	$ 2.7	$ –
Future installment payments to wind farm developer	**–**	2.3	3.9
Supplemental cash flow information			
Cash paid during the period for			
Interest (net of interest capitalized)[A]	**$138.9**	$ 144.6	$125.8
Income taxes (net of income tax refunds)	**4.7**	(139.5)	2.0

(A) Net of interest capitalized of $19.1 million, $8.0 million and $14.6 million in 2011, 2010 and 2009, respectively.

10. Income Taxes

The items comprising income tax expense are as follows:

(In millions, year ended December 31)	2011	2010	2009
Provision (benefit) for current income taxes			
Federal	**$ (6.4)**	$ 15.8	$(145.3)
State	**–**	2.3	(4.8)
Total provision (benefit) for current income taxes	**(6.4)**	18.1	(150.1)
Provision for deferred income taxes, net			
Federal	**160.3**	134.5	256.7
State	**2.9**	9.3	8.1
Total provision for deferred income taxes, net	**163.2**	143.8	264.8
Deferred federal investment tax credits, net	**(3.3)**	(3.7)	(4.2)
Income taxes relating to other income and deductions	**7.2**	2.8	10.6
Total income tax expense	**$160.7**	$161.0	$ 121.1

The Company files consolidated income tax returns in the U.S. Federal jurisdiction and various state jurisdictions. With few exceptions, the Company is no longer subject to U.S. Federal tax examinations by tax authorities for years prior to 2007 or state and local tax examinations by tax authorities for years prior to 2002. Income taxes are generally allocated to each company in the affiliated group based on its stand-alone taxable income or loss. Federal investment tax credits previously claimed on electric utility property have been deferred and are being amortized to income over the life of the related property. OG&E earns both Federal and Oklahoma state tax credits associated with the production from its wind farms. In addition, OG&E and Enogex earn Oklahoma state tax credits associated with their investments in electric generating and natural gas processing facilities which further reduce the Company's effective tax rate. The following schedule reconciles the statutory Federal tax rate to the effective income tax rate:

(Year ended December 31)	**2011**	2010	2009
Statutory Federal tax rate	**35.0%**	35.0%	35.0%
Amortization of net unfunded deferred taxes	**0.7**	0.7	0.7
State income taxes, net of Federal income tax benefit	**0.6**	1.7	1.0
Medicare Part D subsidy	**0.2**	2.6	(1.1)
Qualified production activities	**–**	(0.2)	–
401(k) dividends	**(0.5)**	(0.6)	(0.7)
Federal investment tax credits, net	**(0.7)**	(0.8)	(1.1)
Income attributable to noncontrolling interest	**(1.3)**	(0.4)	–
Federal renewable energy credit [A]	**(3.4)**	(3.4)	(2.2)
Other	**0.1**	0.3	0.1
Effective income tax rate	**30.7%**	34.9%	31.7%

[A] These are credits associated with the production from OG&E's wind farms.

At December 31, 2011 and 2010, the Company had no material unrecognized tax benefits related to uncertain tax positions.

The deferred tax provisions are recognized as costs in the ratemaking process by the commissions having jurisdiction over the rates charged by OG&E. The components of Deferred Income Taxes at December 31, 2011 and 2010, respectively, were as follows:

(In millions, December 31)	**2011**	2010
Current deferred income tax assets		
Net operating losses	**$ 15.8**	$ –
Accrued liabilities	**13.2**	8.2
Accrued vacation	**4.2**	6.1
Uncollectible accounts	**1.4**	0.6
Other	**–**	2.8
Total current deferred income tax assets	**34.6**	17.7
Current accrued income tax liabilities		
Derivative instruments	**(2.5)**	1.0
Total current accrued income tax liabilities	**(2.5)**	1.0
Current deferred income tax assets, net	**$ 32.1**	$ 18.7
Non-current deferred income tax liabilities		
Accelerated depreciation and other property related differences	**$1,449.6**	$1,071.4
Investment in Enogex Holdings	**571.8**	376.1
Company pension plan	**67.5**	71.4
Regulatory asset	**21.2**	17.2
Income taxes refundable to customers, net	**15.9**	16.8
Bond redemption-unamortized costs	**4.4**	4.8
Derivative instruments	**–**	22.4
Total non-current deferred income tax liabilities	**2,130.4**	1,580.1
Non-current deferred income tax assets		
Net operating losses	**(225.2)**	–
Regulatory liabilities	**(65.3)**	(43.7)
State tax credits	**(63.0)**	(35.5)
Postretirement medical and life insurance benefits	**(50.2)**	(39.0)
Federal tax credits	**(49.7)**	(21.5)
Derivative instruments	**(12.8)**	–
Deferred Federal investment tax credits	**(2.3)**	(3.6)
Other	**(10.5)**	(2.0)
Total non-current deferred income tax assets	**(479.0)**	(145.3)
Non-current deferred income tax liabilities, net	**$1,651.4**	$1,434.8

During 2010 and 2011, the Company had a Federal tax operating loss primarily caused by the accelerated tax "bonus" depreciation provision contained within the Tax Relief, Unemployment Insurance Reauthorization and Job Creation Act of 2010 which allows the Company to record a current income tax deduction for 100 percent of the cost of certain property placed into service from September 8, 2010 to December 31, 2011. In addition, the new law also allows the Company to record a current income tax deduction for 50 percent of the cost of certain property placed into service from January 1, 2012 to December 31, 2012. For financial accounting purposes, the Company recorded an increase in its Non-Current Deferred Income Taxes Liability at December 31, 2011 and 2010 on the Company's Consolidated Balance Sheet to recognize the financial statement impact of this new law.

In June 2010, new legislation was passed in Oklahoma that created a moratorium, from July 1, 2010 through June 30, 2012, on 30 income tax credits. For income tax purposes, credits affected by the moratorium may not be claimed for any event, transaction, investment, expenditure or other act for which the credits would otherwise be allowable. During this two-year period, affected credits generated by the Company are being deferred and will be utilized at a time after the moratorium expires. For financial accounting purposes, the Company will receive the benefits in the future as most of these credits do not expire if they are not utilized in the period they are generated.

Medicare Part D Subsidy

On March 23, 2010, the Patient Protection and Affordable Care Act of 2009 was signed into law, and, on March 30, 2010, the Health Care and Education Reconciliation Act of 2010, which makes various amendments to certain aspects of the Patient Protection and Affordable Care Act of 2009, was signed into law. These Acts effectively change the tax treatment of Federal subsidies paid to sponsors of retiree health benefit plans that provide prescription drug benefits that are at least actuarially equivalent to the corresponding benefits provided under Medicare Part D.

The Federal subsidy paid to employers was introduced as part of the Medicare Prescription Drug, Improvement, and Modernization Act of 2003. The Company has been recognizing the Federal subsidy since 2005 related to certain retiree prescription drug plans that were determined to be actuarially equivalent to the benefit provided under Medicare Part D. Under the Medicare Prescription Drug, Improvement, and Modernization Act of 2003, the Federal subsidy does not reduce an employer's income tax deduction for the costs of providing such prescription drug plans nor is it subject to income tax individually.

During 2011, the Company modified its retiree health benefit plan in such a manner that it is no longer actuarially equivalent to the corresponding benefits provided under Medicare Part D. As a result, the Company is no longer eligible to receive Medicare Part D reimbursements. See Note 14 for a further discussion.

Other

The Company sustained Federal and state tax operating losses in 2010 and 2011 caused primarily by bonus depreciation and other book verses tax temporary differences. As a result, the Company accrued Federal and state income tax benefits in 2010 and 2011. The Company can no longer carry these losses back to prior periods, therefore, these losses are being carried forward. In addition to the operating losses, the Company was unable to utilize the various tax credits that were generating during these years. These tax losses and credits are being carried as deferred tax assets and will be utilized in future periods. The Company anticipates future taxable income will be sufficient to utilize all of the losses and credits before they begin to expire, accordingly no valuation allowance is considered necessary. The following table summarizes these carry forwards:

(In millions)	Carry Forward Amount	Deferred Tax Asset	Earliest Expiration Date
Net operating losses			
State operating loss	$772.9	$ 28.4	2030
Federal operating loss	607.2	212.6	2030
Federal tax credits	49.7	49.7	2029
State tax credits			
Oklahoma investment tax credits	76.3	49.7	N/A
Oklahoma capital investment board credits(A)	7.3	7.3	2015
Oklahoma zero emission tax credits	8.4	6.0	2020

(A) *Oklahoma capital investment board credits may not be exercisable after July 1, 2015. The Company anticipates the credits will be monetized or the expiration date of these credits will be extended.*

The Company expects that $45.0 million of the tax loss carry forward will be utilized in 2012 and, as a result, a current deferred tax asset of $15.8 million was recorded at December 31, 2011. The remaining $225.2 million was recorded as a non-current deferred tax asset and is expected to be realized in periods after 2012.

11. Common Equity

Automatic Dividend Reinvestment and Stock Purchase Plan

The Company issued 277,245 shares of common stock under its Automatic Dividend Reinvestment and Stock Purchase Plan in 2011 and received proceeds of $13.8 million. The Company may, from time to time, issue additional shares under its Automatic Dividend Reinvestment and Stock Purchase Plan to fund capital requirements or working capital needs. At December 31, 2011, there were 2,369,043 shares of unissued common stock reserved for issuance under the Company's Automatic Dividend Reinvestment and Stock Purchase Plan.

Earnings Per Share

Basic earnings per share is calculated by dividing net income attributable to OGE Energy by the weighted average number of the Company's common shares outstanding during the period. In the calculation of diluted earnings per share, weighted average shares outstanding are increased for additional shares that would be outstanding if potentially dilutive securities were converted to common stock. Potentially dilutive securities for the Company consist of performance units. Basic and diluted earnings per share for the Company were calculated as follows:

(In millions)	**2011**	2010	2009
Net income attributable to OGE Energy	**$342.9**	$295.3	$258.3
Average common shares outstanding			
Basic average common shares outstanding	**97.9**	97.3	96.2
Effect of dilutive securities:			
Contingently issuable shares (performance units)	**1.3**	1.6	1.0
Diluted average common shares outstanding	**99.2**	98.9	97.2
Basic earnings per average common share attributable to OGE Energy common shareholders	**$ 3.50**	$ 3.03	$ 2.68
Diluted earnings per average common share attributable to OGE Energy common shareholders	**$ 3.45**	$ 2.99	$ 2.66
Anti-dilutive shares excluded from earnings per share calculation	**–**	–	–

12. Long-Term Debt

A summary of the Company's long-term debt is included in the Consolidated Statements of Capitalization. At December 31, 2011, the Company was in compliance with all of its debt agreements.

OG&E has tax-exempt pollution control bonds with optional redemption provisions that allow the holders to request repayment of the bonds at various dates prior to the maturity. The bonds, which can be tendered at the option of the holder during the next 12 months, are as follows:

Series	Date Due	Amount (In millions)
0.22% – 0.44%	Garfield Industrial Authority, January 1, 2025	$ 47.0
0.20% – 0.44%	Muskogee Industrial Authority, January 1, 2025	32.4
0.24% – 0.50%	Muskogee Industrial Authority, June 1, 2027	56.0
Total (redeemable during next 12 months)		$135.4

All of these bonds are subject to an optional tender at the request of the holders, at 100 percent of the principal amount, together with accrued and unpaid interest to the date of purchase. The bond holders, on any business day, can request repayment of the bond by delivering an irrevocable notice to the tender agent stating the principal amount of the bond, payment instructions for the purchase price and the business day the bond is to be purchased. The repayment option may only be exercised by the holder of a bond for the principal amount. When a tender notice has been received by the trustee, a third party remarketing agent for the bonds will attempt to remarket any bonds tendered for purchase. This process occurs once per week. Since the original issuance of these series of bonds in 1995 and 1997, the remarketing agent has successfully remarketed all tendered bonds. If the remarketing agent is unable to remarket any such bonds, OG&E is obligated to repurchase such unremarketed bonds. As OG&E has both the intent and ability to refinance the bonds on a long-term basis and such ability is supported by an ability to consummate the refinancing, the bonds are classified as long-term debt in the Company's Consolidated Financial Statements. OG&E believes that it has sufficient liquidity to meet these obligations.

Long-Term Debt Maturities

Maturities of the Company's long-term debt during the next five years consist of $300 million and $260 million in years 2014 and 2016, respectively. There are no maturities of the Company's long-term debt in years 2012, 2013 or 2015.

The Company has previously incurred costs related to debt refinancings. Unamortized debt expense and unamortized loss on reacquired debt are classified as Deferred Charges and Other Assets and the unamortized premium and discount on long-term debt is classified as Long-Term Debt, respectively, in the Consolidated Balance Sheets and are being amortized over the life of the respective debt.

OG&E Issuance of Long-Term Debt

On May 24, 2011, OG&E issued $250 million of 5.25% senior notes due May 15, 2041. The proceeds from the issuance were added to OGE Energy's general funds and were used to repay short-term debt. OG&E expects to issue additional long-term debt from time to time when market conditions are favorable and when the need arises.

13. Short-Term Debt and Credit Facilities

The Company borrows on a short-term basis, as necessary, by the issuance of commercial paper and by borrowings under its revolving credit agreements. The short-term debt balance was $277.1 million and $145.0 million at December 31, 2011 and 2010, respectively, at a weighted-average interest rate of 0.48 percent and 0.34 percent, respectively. The following table provides information regarding the Company's revolving credit agreements and available cash at December 31, 2011.

(In millions)	Aggregate Commitment	Amount Outstanding [A]	Weighted-Average Interest Rate	Maturity
Revolving credit agreements and available cash				
OGE Energy[B]	$ 750.0	$277.1	0.48%[D]	12/13/16[F]
OG&E[C]	400.0	2.2	0.53%[D]	12/13/16[F]
Enogex LLC[E]	400.0	150.0	1.65%[D]	12/13/16[F]
	1,550.0	429.3	0.89%	
Cash	4.6	N/A	N/A	N/A
Total	$1,554.6	$429.3	0.89%	

[A] Includes direct borrowings under the revolving credit agreements, commercial paper borrowings and letters of credit at December 31, 2011.

[B] This bank facility is available to back up OGE Energy's commercial paper borrowings and to provide revolving credit borrowings. This bank facility can also be used as a letter of credit facility. At December 31, 2011, there was $277.1 million in outstanding commercial paper borrowings.

[C] This bank facility is available to back up OG&E's commercial paper borrowings and to provide revolving credit borrowings. This bank facility can also be used as a letter of credit facility. At December 31, 2011, there was $2.2 million supporting letters of credit.

[D] Represents the weighted-average interest rate for the outstanding borrowings under the revolving credit agreements, commercial paper borrowings and letters of credit.

[E] This bank facility is available to provide revolving credit borrowings for Enogex LLC. As Enogex LLC's credit agreement matures on December 13, 2016, along with its intent in utilizing its credit agreement, borrowings thereunder are classified as long-term debt in the Company's Consolidated Balance Sheets.

[F] In December 2011, the Company, OG&E and Enogex LLC each entered into new unsecured five-year revolving credit facilities totaling in the aggregate $1,550 million ($750 million for the Company, $400 million for OG&E and $400 million for Enogex LLC). Each of the credit facilities contain an option, which may be exercised up to two times, to extend the term for an additional year.

The Company's ability to access the commercial paper market could be adversely impacted by a credit ratings downgrade or major market disruptions. Pricing grids associated with the Company's credit facilities could cause annual fees and borrowing rates to increase if an adverse ratings impact occurs. The impact of any future downgrade could include an increase in the costs of the Company's short-term borrowings, but a reduction in the Company's credit ratings would not result in any defaults or accelerations. Any future downgrade of the Company could also lead to higher long-term borrowing costs and, if below investment grade, would require the Company to post cash collateral or letters of credit.

OG&E must obtain regulatory approval from the FERC in order to borrow on a short-term basis. OG&E has the necessary regulatory approvals to incur up to $800 million in short-term borrowings at any one time for a two-year period beginning January 1, 2011 and ending December 31, 2012.

14. Retirement Plans and Postretirement Benefit Plans

Pension Plan and Restoration of Retirement Income Plan

In October 2009, the Company's Pension Plan and the Company's qualified defined contribution retirement plan ("401(k) Plan") were amended, effective January 1, 2010 to provide eligible employees a choice to select a future retirement benefit combination from the Company's Pension Plan and the Company's 401(k) Plan.

Employees hired or rehired on or after December 1, 2009 do not participate in the Pension Plan but are eligible to participate in the 401(k) Plan where, for each pay period, the Company contributes to the 401(k) Plan, on behalf of each participant, 200 percent of the participant's contributions up to five percent of compensation.

It is the Company's policy to fund the Pension Plan on a current basis based on the net periodic pension expense as determined by the Company's actuarial consultants. During each of 2011 and 2010, OGE Energy made contributions to its Pension Plan of $50 million to help ensure that the Pension Plan maintains an adequate funded status. Such contributions are intended to provide not only for benefits attributed to service to date, but also for those expected to be earned in the future. During 2012, OGE Energy may contribute up to $35 million to its Pension Plan. The expected contribution to the Pension Plan during 2012 would be a discretionary contribution, anticipated to be in the form of cash, and is not required to satisfy the minimum regulatory funding requirement specified by the Employee Retirement Income Security Act of 1974, as amended. OGE Energy could be required to make additional contributions if the value of its pension trust and postretirement benefit plan trust assets are adversely impacted by a major market disruption in the future.

The Company provides a Restoration of Retirement Income Plan to those participants in the Company's Pension Plan whose benefits are subject to certain limitations under the Internal Revenue Code of 1986 (the "Code"). The benefits payable under this Restoration of Retirement Income Plan are equivalent to the amounts that would have been payable under the Pension Plan but for these limitations. The Restoration of Retirement Income Plan is intended to be an unfunded plan.

The following table presents the status of the Company's Pension Plan and Restoration of Retirement Income Plan at December 31, 2011 and 2010. These amounts have been recorded in Accrued Benefit Obligations with the offset in Accumulated Other Comprehensive Loss (except OG&E's portion which is recorded as a regulatory asset as discussed in Note 1) in the Company's Consolidated Balance Sheet. The amounts in Accumulated Other Comprehensive Loss and those recorded as a regulatory asset represent a net periodic benefit cost to be recognized in the Consolidated Statements of Income in future periods.

	Pension Plan		Restoration of Retirement Income Plan	
(In millions, December 31)	**2011**	2010	**2011**	2010
Benefit obligations	**$(697.7)**	$(640.9)	**$(13.3)**	$(10.8)
Fair value of plan assets	**589.8**	574.0	**–**	–
Funded status at end of year	**$(107.9)**	$ (66.9)	**$(13.3)**	$(10.8)

The following table summarizes the benefit payments the Company expects to pay related to its Pension Plan and Restoration of Retirement Income Plan. These expected benefits are based on the same assumptions used to measure the Company's benefit obligation at the end of the year and include benefits attributable to estimated future employee service.

(In millions)	Projected Benefit Payments
2012	$ 68.2
2013	69.2
2014	87.0
2015	78.3
2016	71.1
2017 and beyond	303.3

Plan Investments, Policies and Strategies

The Pension Plan assets are held in a trust which follows an investment policy and strategy designed to reduce the funded status volatility of the Plan by utilizing liability driven investing. The purpose of liability driven investing is to structure the asset portfolio to more closely resemble the pension liability and thereby more effectively hedge against changes in the liability. The investment policy follows a glide path approach that shifts a higher portfolio weighting to fixed income as the Plan's funded status increases. The table below sets forth the targeted fixed income and equity allocations at different funded status levels.

Projected Benefit Obligation Funded Status Thresholds	<90%	95%	100%	105%	110%	115%	120%
Fixed income	50%	58%	65%	73%	80%	85%	90%
Equity	50%	42%	35%	27%	20%	15%	10%
Total	100%	100%	100%	100%	100%	100%	100%

Within the portfolio's overall allocation to equities, the funds are allocated according to the guidelines in the table below.

Asset Class	Target Allocation	Minimum	Maximum
Domestic all-cap/large cap equity	50%	50%	60%
Domestic mid-cap equity	15%	5%	25%
Domestic small-cap equity	15%	5%	25%
International equity	20%	10%	30%

The Company has retained an investment consultant responsible for the general investment oversight, analysis, monitoring investment guideline compliance and providing quarterly reports to certain of the Company's members and the Company's Investment Committee. The various investment managers used by the trust operate within the general operating objectives as established in the investment policy and within the specific guidelines established for each investment manager's respective portfolio.

The portfolio is rebalanced on an annual basis to bring the asset allocations of various managers in line with the target asset allocation listed above. More frequent rebalancing may occur if there are dramatic price movements in the financial markets which may cause the trust's exposure to any asset class to exceed or fall below the established allowable guidelines.

To evaluate the progress of the portfolio, investment performance is reviewed quarterly. It is, however, expected that performance goals will be met over a full market cycle, normally defined as a three to five year period. Analysis of performance is within the context of the prevailing investment environment and the advisors' investment style. The goal of the trust is to provide a rate of return consistently from three percent to five percent over the rate of inflation (as measured by the national Consumer Price Index) on a fee adjusted basis over a typical market cycle of no less than three years and no more than five years. Each investment manager is expected to outperform its respective benchmark. Below is a list of each asset class utilized with appropriate comparative benchmark(s) each manager is evaluated against:

Asset Class	Comparative Benchmark(s)
Core Fixed Income	Barclays Capital Aggregate Index
Interest Rate Sensitive Fixed Income	Barclays Capital Aggregate Index
Long Duration Fixed Income	Barclays Capital Aggregate Index
Equity Index	Standard & Poor's 500 Index
All-Cap Equity	Russell 3000 Index
	Russell 3000 Value Index
Mid-Cap Equity	Russell Midcap Index
	Russell Midcap Value Index
Small-Cap Equity	Russell 2000 Index
	Russell 2000 Value Index
International Equity	Morgan Stanley Capital International ACWI ex-US

The fixed income manager is expected to use discretion over the asset mix of the trust assets in its efforts to maximize risk-adjusted performance. Exposure to any single issuer, other than the U.S. government, its agencies, or its instrumentalities (which have no limits) is limited to five percent of the fixed income portfolio as measured by market value. At least 75 percent of the invested assets must possess an investment grade rating at or above Baa3 or BBB- by Moody's Investors Services, Standard & Poor's Ratings Services or Fitch Ratings. The portfolio may invest up to 10 percent of the portfolio's market value in convertible bonds as long as the securities purchased meet the quality guidelines. The purchase of any of the Company's equity, debt or other securities is prohibited.

The domestic value equity managers focus on stocks that the manager believes are undervalued in price and earn an average or less than average return on assets, and often pays out higher than average dividend payments. The domestic growth equity manager will invest primarily in growth companies which consistently experience above average growth in earnings and sales, earn a high return on assets, and reinvest cash flow into existing business. The domestic mid-cap equity portfolio manager focuses on companies with market capitalizations lower than the average company traded on the public exchanges with the following characteristics: price/earnings ratio at or near the Russell Midcap Index, small dividend yield, return on equity at or near the Russell Midcap Index and an earnings per share growth rate at or near the Russell Midcap Index. The domestic small-cap equity manager will purchase shares of companies with market capitalizations lower than the average company traded on the public exchanges with the following characteristics: price/earnings ratio at or near the Russell 2000, small dividend yield, return on equity at or near the Russell 2000 and an earnings per share growth rate at or near the Russell 2000. The international global equity manager invests primarily in non-dollar denominated equity securities. Investing internationally diversifies the overall trust across the global equity markets. The manager is required to operate under certain restrictions including: regional constraints, diversification requirements and percentage of U.S. securities. The Morgan Stanley Capital International All Country World ex-US Index is the benchmark for comparative performance purposes. The Morgan Stanley Capital International All Country World ex-US Index is a market value weighted index designed to measure the combined equity market performance of developed and emerging markets countries, excluding the United States.

All of the equities which are purchased for the international portfolio are thoroughly researched. Only companies with a market capitalization in excess of $100 million are allowable. No more than five percent of the portfolio can be invested in any one stock at the time of purchase. All securities are freely traded on a recognized stock exchange and there are no 144-A securities and no over-the-counter derivatives. The following investment categories are excluded: options (other than traded currency options), commodities, futures (other than currency futures or currency hedging), short sales/margin purchases, private placements, unlisted securities and real estate (but not real estate shares).

For all domestic equity investment managers, no more than eight percent (five percent for mid-cap and small-cap equity managers) can be invested in any one stock at the time of purchase and no more than 16 percent (10 percent for mid-cap and small-cap equity managers) after accounting for price appreciation. Options or financial futures may not be purchased unless prior approval of the Company's Investment Committee is received. The purchase of securities on margin is prohibited as is securities lending. Private placement or venture capital may not be purchased. All interest and dividend payments must be swept on a daily basis into a short-term money market fund for re-deployment. The purchase of any of the Company's equity, debt or other securities is prohibited. The purchase of equity or debt issues of the portfolio manager's organization is also prohibited. The aggregate positions in any company may not exceed one percent of the fair market value of its outstanding stock.

Plan Investments

The following tables summarize the Pension Plan's investments that are measured at fair value on a recurring basis at December 31, 2011 and 2010. There were no Level 3 investments held by the Pension Plan at December 31, 2011 and 2010.

(In millions, December 31)	2011	Level 1	Level 2
Common stocks			
U.S. common stocks	$179.7	$179.7	$ –
Foreign common stocks	59.5	59.5	–
Bonds, debentures and notes(A)			
Corporate fixed income and other securities	95.3	–	95.3
Mortgage-backed securities	17.2	–	17.2
U.S. Government obligations			
U.S. treasury notes and bonds(B)	118.8	118.8	–
Mortgage-backed securities	72.0	–	72.0
Other securities	1.0	–	1.0
Commingled fund(C)	38.5	–	38.5
Common/collective trust(D)	29.6	–	29.6
Foreign government bonds	2.9	–	2.9
Interest-bearing cash	2.1	2.1	–
U.S. municipal bonds	1.7	–	1.7
Preferred stocks (foreign)	0.6	0.6	–
Total Plan investments	$618.9	$360.7	$258.2
Receivable from broker for securities sold	4.8		
Interest and dividends receivable	3.1		
Payable to broker for securities purchased	(37.0)		
Total Plan assets	$589.8		

(In millions, December 31)	2010	Level 1	Level 2
Common stocks			
U.S. common stocks	$189.0	$189.0	$ –
Foreign common stocks	75.9	75.9	–
Bonds, debentures and notes[(A)]			
Corporate fixed income and other securities	104.1	–	104.1
Mortgage-backed securities	26.6	–	26.6
U.S. Government obligations			
Mortgage-backed securities	76.5	–	76.5
U.S. treasury notes and bonds[(B)]	35.7	35.7	–
Other securities	2.4	–	2.4
Commingled fund[(C)]	37.7	–	37.7
Common/collective trust[(D)]	23.1	–	23.1
Mutual funds			
Global equity mutual fund	1.8	1.8	–
U.S. equity mutual fund	1.6	1.6	–
Foreign equity mutual fund	1.0	1.0	–
U.S. municipal bonds	4.3	–	4.3
Foreign government bonds	3.9	–	3.9
Repurchase agreement	3.7	–	3.7
Preferred stocks (foreign)	0.7	0.7	–
Interest-bearing cash	0.2	0.2	–
Total Plan investments	$588.2	$305.9	$282.3
Receivable from broker for securities sold	5.5		
Interest and dividends receivable	2.8		
Payable to broker for securities purchased	(22.5)		
Total Plan assets	$574.0		

(A) *This category primarily represents U.S. corporate bonds with an investment grade rating at or above Baa3 or BBB- by Moody's Investors Services, Standard & Poor's Ratings Services or Fitch Ratings.*

(B) *This category represents U.S. treasury notes and bonds with a Moody's Investors Services rating of Aaa and Government Agency Bonds with a Moody's Investors Services rating of A1 or higher.*

(C) *This category represents units of participation in a commingled fund that primarily invest in stocks and bonds of U.S. companies.*

(D) *This category represents units of participation in an investment pool which primarily invests in foreign or domestic bonds, debentures, mortgages, equipment or other trust certificates, notes, obligations issued or guaranteed by the U.S. Government or its agencies, bank certificates of deposit, bankers' acceptances and repurchase agreements, high grade commercial paper and other instruments with money market characteristics with a fixed or variable interest rate. There are no restrictions on redemptions in the common/collective trust.*

The three levels defined in the fair value hierarchy and examples of each are as follows:

Level 1 inputs are quoted prices in active markets for identical unrestricted assets or liabilities that are accessible by the Pension Plan at the measurement date. Instruments classified as Level 1 include investments in common and preferred stocks, U.S. treasury notes and bonds, mutual funds and interest-bearing cash.

Level 2 inputs are inputs other than quoted prices in active markets included within Level 1 that are either directly or indirectly observable at the reporting date for the asset or liability for substantially the full term of the asset or liability. Level 2 inputs include quoted prices for similar assets or liabilities in active markets and quoted prices for identical or similar assets or liabilities in markets that are not active. Instruments classified as Level 2 include corporate fixed income and other securities, mortgage-backed securities, other U.S. Government obligations, commingled fund, a common/collective trust, U.S. municipal bonds, foreign government bonds, a repurchase agreement, money market fund and forward contracts.

Level 3 inputs are prices or valuation techniques for the asset or liability that require inputs that are both significant to the fair value measurement and unobservable (i.e., supported by little or no market activity). Unobservable inputs reflect the Plan's own assumptions about the assumptions that market participants would use in pricing the asset or liability (including assumptions about risk).

Postretirement Benefit Plans

In addition to providing pension benefits, the Company provides certain medical and life insurance benefits for eligible retired members. Regular, full-time, active employees hired prior to February 1, 2000 whose age and years of credited service total or exceed 80 or have attained at least age 55 with 10 or more years of service at the time of retirement are entitled to postretirement medical benefits while employees hired on or after February 1, 2000 are not entitled to postretirement medical benefits. Effective January 1, 2010, the age for dependents to participate in the Company's Medical Plan was increased to age 21 and if the dependent is a full-time student to age 26. Effective July 1, 2010, the age for dependents to participate in the Company's Medical Plan was increased to age 26 without regard to their full-time student status. All regular, full-time, active employees whose age and years of credited service total or exceed 80 or have attained at least age 55 with three or more years of service at the time of retirement are entitled to postretirement life insurance benefits. Eligible retirees must contribute such amount as the Company specifies from time to time toward the cost of coverage for postretirement benefits. The benefits are subject to deductibles, co-payment provisions and other limitations. OG&E charges to expense the postretirement benefit costs and includes an annual amount as a component of the cost-of-service in future ratemaking proceedings.

In January 2011, the Company adopted several amendments to its retiree medical plan. Effective January 1, 2012, medical costs for pre-65 aged eligible retirees are fixed at the 2011 level and the Company covers future annual medical inflationary cost increases up to five percent. Increases in excess of five percent annually are covered by the pre-65 aged retiree in the form of premium increases. Also, effective January 1, 2012, the Company supplements Medicare coverage for Medicare-eligible retirees, providing them a fixed stipend based on the Company's expected average 2011 premium for medical and drug coverage, and allows those Medicare-eligible retirees to acquire coverage from a Company-provided third-party administrator. The effect of these plan amendments was reflected in the Company's 2011 Consolidated Balance Sheet as a reduction to the accumulated postretirement benefit obligation of $91.3 million, an increase in other comprehensive income of $16.9 million and a reduction to OG&E's benefit obligations regulatory asset of $74.4 million.

Plan Investments

The following tables summarize the postretirement benefit plans investments that are measured at fair value on a recurring basis at December 31, 2011 and 2010. There were no Level 2 investments held by the postretirement benefit plans at December 31, 2011 and 2010.

(In millions, December 31)	2011	Level 1	Level 3
Group retiree medical insurance contract[(A)]	**$54.3**	**$ –**	**$54.3**
Mutual funds investment			
U.S. equity investments	**5.3**	**5.3**	**–**
Money market funds investment	**0.7**	**0.7**	**–**
Cash	**0.7**	**0.7**	**–**
Total Plan investments	**$61.0**	**$6.7**	**$54.3**

(A) *This category represents a group retiree medical insurance contract which invests in a pool of common stocks, bonds and money market accounts, of which a significant portion is comprised of mortgage-backed securities.*

(In millions, December 31)	2010	Level 1	Level 3
Group retiree medical insurance contract[(A)]	$52.4	$ –	$52.4
Mutual funds investment			
U.S. equity investments	5.5	5.5	–
Money market funds investment	0.6	0.6	–
Total Plan investments	$58.5	$6.1	$52.4

(A) *This category represents a group retiree medical insurance contract which invests in a pool of common stocks, bonds and money market accounts, of which a significant portion is comprised of mortgage-backed securities.*

The postretirement benefit plans Level 3 investment includes an investment in a group retiree medical insurance contract. The unobservable input included in the valuation of the contract includes the approach for determining the allocation of the postretirement benefit plans pro-rata share of the total assets in the contract.

The following table summarizes the postretirement benefit plans investments that are measured at fair value on a recurring basis using significant unobservable inputs (Level 3).

(In millions, year ended December 31)	2011
Group retiree medical insurance contract	
Beginning balance	**$52.4**
Interest income	**1.3**
Net unrealized gains related to instruments held at the reporting date	**0.9**
Dividend income	**0.8**
Realized gains	**0.1**
Administrative expenses and charges	**(0.1)**
Claims paid	**(1.1)**
Ending balance	**$54.3**

The following table presents the status of the Company's postretirement benefit plans at December 31, 2011 and 2010. These amounts have been recorded in Accrued Benefit Obligations with the offset in Accumulated Other Comprehensive Loss (except OG&E's portion which is recorded as a regulatory asset as discussed in Note 1) in the Company's Consolidated Balance Sheet. The amounts in Accumulated Other Comprehensive Loss and those recorded as a regulatory asset represent a net periodic benefit cost to be recognized in the Consolidated Statements of Income in future periods.

(In millions, December 31)	2011	2010
Benefit obligations	**$(280.6)**	$(337.1)
Fair value of plan assets	**61.0**	58.5
Funded status at end of year	**$(219.6)**	$(278.6)

The assumed health care cost trend rates have a significant effect on the amounts reported for postretirement medical benefit plans. Future health care cost trend rates are assumed to be 8.75 percent in 2012 with the rates trending downward to 4.48 percent by 2028. A one-percentage point change in the assumed health care cost trend rate would have the following effects:

(In millions, year ended December 31)	2011	2010	2009
One-percentage point increase			
Effect on aggregate of the service and interest cost components	**$ –**	$3.1	$ 2.4
Effect on accumulated postretirement benefit obligations	**0.1**	0.7	40.3
One-percentage point decrease			
Effect on aggregate of the service and interest cost components	**$0.1**	$2.5	$ 1.9
Effect on accumulated postretirement benefit obligations	**0.6**	1.6	32.9

Medicare Prescription Drug, Improvement and Modernization Act of 2003

On December 8, 2003, President Bush signed into law the Medicare Prescription Drug, Improvement and Modernization Act of 2003, which expanded Medicare to include, for the first time, coverage for prescription drugs. The following table summarizes the gross benefit payments the Company expects to pay related to its postretirement benefit plans, including prescription drug benefits. The Company received $1.3 million in Federal subsidy receipts in 2011. Due to amendments in the Company's retiree medical plan discussed above, the Company does not expect to receive any additional Federal subsidies in the future.

(In millions)	Gross Projected Postretirement Benefit Payments
2012	$15.4
2013	16.0
2014	16.9
2015	17.7
2016	18.3
2017 and Beyond	97.0

Early Retiree Reinsurance Program

The Patient Protection and Affordable Care Act of 2010 authorized a temporary reinsurance program to pay certain employment-based group health plans up to 80 percent of each early retiree's annual claims cost between $15,000 and $90,000. The program will end by the earlier of January 1, 2014 or when the limited $5 billion in funding runs out. The Company received $0.7 million in Federal subsidy receipts in 2011. The Company's reimbursement proceeds are excluded from gross income and were used to reduce the health benefit costs for the plan and to reduce premium contributions for the plan participants. The Company does not expect to receive any additional benefits provided by this program.

Obligations and Funded Status

The following table presents the status of the Company's Pension Plan, the Restoration of Retirement Income Plan and the postretirement benefit plans for 2011 and 2010. The benefit obligation for the Company's Pension Plan and the Restoration of Retirement Income Plan represents the projected benefit obligation, while the benefit obligation for the postretirement benefit plans represents the accumulated postretirement benefit obligation. The accumulated postretirement benefit obligation for the Company's Pension Plan and Restoration of Retirement Income Plan differs from the projected benefit obligation in that the former includes no assumption about future compensation levels. The accumulated postretirement benefit obligation for the Pension Plan and the Restoration of Retirement Income Plan at December 31, 2011 was $656.1 million and $11.9 million, respectively. The accumulated postretirement benefit obligation for the Pension Plan and the Restoration of Retirement Income Plan at December 31, 2010 was $601.4 million and $8.7 million, respectively. The details of the funded status of the Pension Plan, the Restoration of Retirement Income Plan and the postretirement benefit plans and the amounts included in the Consolidated Balance Sheets are as follows:

	Pension Plan		Restoration of Retirement Income Plan		Postretirement Benefit Plans	
(In millions, December 31)	**2011**	2010	**2011**	2010	**2011**	2010
Change in benefit obligation						
Beginning obligations	**$(640.9)**	$(610.9)	**$(10.8)**	$ (8.3)	**$(337.1)**	$(288.0)
Service cost	**(17.6)**	(16.7)	**(1.0)**	(0.9)	**(3.5)**	(4.3)
Interest cost	**(33.3)**	(31.8)	**(0.6)**	(0.5)	**12.5**	(17.0)
Plan amendments	**–**	–	**–**	–	**91.4**	–
Participants' contributions	**–**	–	**–**	–	**(8.1)**	(7.3)
Medicare subsidies received	**–**	–	**–**	–	**(2.0)**	(1.4)
Actuarial gains (losses)	**(48.3)**	(15.9)	**(1.0)**	(1.5)	**(25.7)**	(36.6)
Benefits paid	**42.4**	34.4	**0.1**	0.4	**16.9**	17.5
Ending obligations	**$(697.7)**	$(640.9)	**$(13.3)**	$(10.8)	**$(280.6)**	$(337.1)
Change in plans' assets						
Beginning fair value	**$ 574.0**	$ 496.3	**$ –**	$ –	**$ 58.5**	$ 55.0
Actual return on plans' assets	**8.2**	62.1	**–**	–	**2.7**	5.2
Employer contributions	**50.0**	50.0	**0.1**	0.4	**6.6**	7.1
Participants' contributions	**–**	–	**–**	–	**8.1**	7.3
Medicare subsidies received	**–**	–	**–**	–	**2.0**	1.4
Benefits paid	**(42.4)**	(34.4)	**(0.1)**	(0.4)	**(16.9)**	(17.5)
Ending fair value	**589.8**	574.0	**–**	–	**61.0**	58.5
Funded status at end of year	**$(107.9)**	$ (66.9)	**$(13.3)**	$(10.8)	**$(219.6)**	$(278.6)

Net Periodic Benefit Cost

	Pension Plan			Restoration of Retirement Income Plan			Postretirement Benefit Plans		
(In millions, year ended December 31)	**2011**	2010	2009	**2011**	2010	2009	**2011**	2010	2009
Service cost	**$17.6**	$ 16.7	$ 18.1	**$1.0**	$0.9	$0.7	**$ 3.5**	$ 4.3	$ 3.3
Interest cost	**33.3**	31.8	31.4	**0.6**	0.5	0.4	**12.5**	17.0	14.1
Expected return on plan assets	**(45.5)**	(42.4)	(33.0)	**–**	–	–	**(5.1)**	(6.9)	(6.5)
Amortization of transition obligation	**–**	–	–	**–**	–	–	**2.7**	2.7	2.7
Amortization of net loss	**19.2**	21.3	23.5	**0.4**	0.3	0.3	**18.3**	12.1	5.0
Amortization of unrecognized prior service cost(A)	**2.4**	2.4	0.8	**0.7**	0.7	0.6	**(16.5)**	–	1.0
Net periodic benefit cost(B)	**$27.0**	$ 29.8	$ 40.8	**$2.7**	$2.4	$2.0	**$ 15.4**	$29.2	$19.6

(A) Unamortized prior service cost is amortized on a straight-line basis over the average remaining service period to the first eligibility age of participants who are expected to receive a benefit and are active at the date of the plan amendment.

(B) In addition to the $45.1 million, $61.4 million and $62.4 million of net periodic benefit cost recognized in 2011, 2010 and 2009, respectively, the Company recognized the following:

- *An increase in pension expense in 2011 and 2010 of $10.8 million and $8.1 million, respectively, and a reduction in pension expense in 2009 of $2.2 million to maintain the allowable amount to be recovered for pension expense in the Oklahoma jurisdiction which are included in the Pension tracker regulatory liability (see Note 1);*
- *A reduction in pension expense in 2009 of $3.2 million in the Arkansas jurisdiction to reflect the approval of recovery of OG&E's 2006 and 2007 pension settlement costs in the May 2009 Arkansas rate order which are included in the Pension tracker regulatory liability) (see Note 1); and*
- *An increase in postretirement medical expense in 2011 of $3.5 million to maintain the allowable amount to be recovered for postretirement medical expense in the Oklahoma jurisdiction which are included in the Pension tracker regulatory liability (see Note 1).*

The capitalized portion of the net periodic pension benefit cost was $6.1 million, $6.5 million and $8.4 million at December 31, 2011, 2010 and 2009, respectively. The capitalized portion of the net periodic postretirement benefit cost was $3.8 million, $6.5 million and $4.1 million at December 31, 2011, 2010 and 2009, respectively.

Rate Assumptions

	Pension Plan and Restoration of Retirement Income Plan			Postretirement Benefit Plans		
(Year ended December 31)	**2011**	2010	2009	**2011**	2010	2009
Discount rate	**4.50%**	5.30%	5.30%	**4.50%**	5.30%	6.00%
Rate of return on plans' assets	**8.00%**	8.50%	8.50%	**6.50%**	8.50%	8.50%
Compensation increases	**4.40%**	4.40%	4.50%	**N/A**	N/A	N/A
Assumed health care cost trend:						
Initial trend	**N/A**	N/A	N/A	**8.75%**	8.99%	9.49%
Ultimate trend rate	**N/A**	N/A	N/A	**4.48%**	5.00%	5.00%
Ultimate trend year	**N/A**	N/A	N/A	**2028**	2020	2018

N/A – not applicable

The overall expected rate of return on plan assets assumption decreased from 8.50 percent in 2010 to 8.00 percent in 2011 in determining net periodic benefit cost due to recent returns on the Company's long-term investment portfolio. The rate of return on plan assets assumption is the average long-term rate of earnings expected on the funds currently invested and to be invested for the purpose of providing benefits specified by the Pension Plan or postretirement benefit plans. This assumption is reexamined at least annually and updated as necessary. The rate of return on plan assets assumption reflects a combination of historical return analysis, forward-looking return expectations and the plans' current and expected asset allocation.

Post-Employment Benefit Plan

Disabled employees receiving benefits from the Company's Group Long-Term Disability Plan are entitled to continue participating in the Company's Medical Plan along with their dependents. The post-employment benefit obligation represents the actuarial present value of estimated future medical benefits that are attributed to employee service rendered prior to the date as of which such information is presented. The obligation also includes future medical benefits expected to be paid to current employees participating in the Company's Group Long-Term Disability Plan and their dependents, as defined in the Company's Medical Plan.

The post-employment benefit obligation is determined by an actuary on a basis similar to the accumulated postretirement benefit obligation. The estimated future medical benefits are projected to grow with expected future medical cost trend rates and are discounted for interest at the discount rate and for the probability that the participant will discontinue receiving benefits from the Company's Group Long-Term Disability Plan due to death, recovery from disability, or eligibility for retiree medical benefits. The Company's post-employment benefit obligation was $2.4 million and $2.1 million at December 31, 2011 and 2010, respectively.

401(k) Plan

The Company provides a 401(k) Plan. Each regular full-time employee of the Company or a participating affiliate is eligible to participate in the 401(k) Plan immediately. All other employees of the Company or a participating affiliate are eligible to become participants in the 401(k) Plan after completing one year of service as defined in the 401(k) Plan. Participants may contribute each pay period any whole percentage between two percent and 19 percent of their compensation, as defined in the 401(k) Plan, for that pay period. Participants who have attained age 50 before the close of a year are allowed to make additional contributions referred to as "Catch-Up Contributions," subject to the limitations of the Code. The 401(k) Plan also allows an eligible automatic contribution arrangement and provides for a qualified default investment alternative consistent with the U.S. Department of Labor regulations. Participants may elect, in accordance with the 401(k) Plan procedures, to have his or her salary deferral rate to be made in the future automatically increased annually on a date and in an amount as specified by the participant in such election. The 401(k) Plan was amended in October 2009, as discussed previously, whereby employees were offered a choice to either stay in the 401(k) Plan (prior to it being amended) where the Company matching contributions are discussed below or select an option whereby, effective January 1, 2010, the Company contributes on behalf of each participant, depending on the option selected, 200 percent of the participant's contributions up to five percent of compensation or 100 percent of the participant's contributions up to six percent of compensation. In the 401(k) Plan (prior to it being amended), the Company contributes to the 401(k) Plan each pay period, on behalf of each participant, an amount equal to 50 percent of the participant's contributions up to six percent of compensation for participants whose employment or re-employment date occurred before February 1, 2000 and who have less than 20 years of service, as defined in the 401(k) Plan, and an amount equal to 75 percent of the participant's contributions up to six percent of compensation for participants whose employment or re-employment date occurred before February 1, 2000 and who have 20 or more years of service, as defined in the 401(k) Plan. For participants whose employment or re-employment date occurred on or after February 1, 2000 and before December 1, 2009, under the 401(k) Plan (prior to it being amended), the Company contributes 100 percent of the participant's contributions up to six percent of compensation. For participants hired on or after December 1, 2009, the Company contributes, effective January 1, 2010, 200 percent of the participant's contributions up to five percent of compensation. No Company contributions are made with respect to a participant's Catch-Up Contributions, rollover contributions, or with respect to a participant's contributions based on overtime payments, pay-in-lieu of overtime for exempt personnel, special lump-sum recognition awards and lump-sum merit awards included in compensation for determining the amount of participant contributions. Prior to January 1, 2010, the Company's contribution, which was initially allocated for investment to the OGE Energy Corp. Common Stock Fund, was made in shares of the Company's common stock or in cash which was used to invest in the Company's common stock. Once made, the Company's contribution could be reallocated, on any business day, by participants to other available investment options. The 401(k) Plan was amended effective January 1, 2010, whereby the Company's contribution may be directed to any available investment option in the 401(k) Plan. The Company match contributions vest over a three-year period. After two years of service, participants become 20 percent vested in their Company contribution account and become fully vested on completing three years of service. In addition, participants fully vest when they are eligible for normal or early retirement under Pension Plan, in the event of their termination due to death or permanent disability or upon attainment of age 65 while employed by the Company or its affiliates. The Company contributed $12.3 million, $11.4 million and $9.3 million in 2011, 2010 and 2009, respectively, to the 401(k) Plan.

Deferred Compensation Plan

The Company provides a nonqualified deferred compensation plan which is intended to be an unfunded plan. The plan's primary purpose is to provide a tax-deferred capital accumulation vehicle for a select group of management, highly compensated employees and non-employee members of the Board of Directors of the Company and to supplement such employees' 401(k) Plan contributions as well as offering this plan to be competitive in the marketplace.

Eligible employees who enroll in the plan have the following deferral options: (i) eligible employees may elect to defer up to a maximum of 70 percent of base salary and 100 percent of annual bonus awards or (ii) eligible employees may elect a deferral percentage of base salary and bonus awards based on the deferral percentage elected for a year under the 401(k) Plan with such deferrals to start when maximum deferrals to the qualified 401(k) Plan have been made because of limitations in that plan. Eligible directors who enroll in the plan may elect to defer up to a maximum of 100 percent of directors' meeting fees and annual retainers. The Company matches employee (but not non-employee director) deferrals to make up for any match lost in the 401(k) Plan because of deferrals to the deferred compensation plan, and to allow for a match that would have been made under the 401(k) Plan on that portion of either the first six percent of total compensation or the first five percent of total compensation, depending on the option the participant elected under the choice provided to eligible employees discussed above, deferred that exceeds the limits allowed in the 401(k) Plan. Matching credits vest based on years of service, with full vesting after six years or, if earlier, on retirement, disability, death, a change in control of the Company or termination of the plan. The deferred compensation plan was amended, effective January 1, 2012, to provide for full vesting after three years. In addition, the Benefits Committee may award discretionary employer contribution credits to a participant under the plan. The Company accounts for the contributions related to the Company's executive officers in this plan as Accrued Benefit Obligations and the Company accounts for the contributions related to the Company's directors in this plan as Other Deferred Credits and Other Liabilities in the Consolidated Balance Sheets. The investment associated with these contributions is accounted for as Other Property and Investments in the Consolidated Balance Sheets. The appreciation of these investments is accounted for as Other Income and the increase in the liability under the plan is accounted for as Other Expense in the Consolidated Statements of Income.

Supplemental Executive Retirement Plan

The Company provides a supplemental executive retirement plan in order to attract and retain lateral hires or other executives designated by the Compensation Committee of the Company's Board of Directors who may not otherwise qualify for a sufficient level of benefits under the Company's Pension Plan and Restoration of Retirement Income Plan. The supplemental executive retirement plan is intended to be an unfunded plan and not subject to the benefit limits imposed by the Code.

15. Report of Business Segments

The Company's business is divided into four segments for financial reporting purposes. These segments are as follows: (i) electric utility, which is engaged in the generation, transmission, distribution and sale of electric energy, (ii) natural gas transportation and storage, (iii) natural gas gathering and processing and (iv) natural gas marketing. Other Operations primarily includes the operations of the holding company. Intersegment revenues are recorded at prices comparable to those of unaffiliated customers and are affected by regulatory considerations. In reviewing its segment operating results, the Company focuses on operating income as its measure of segment profit and loss, and, therefore, has presented this information below. The following tables summarize the results of the Company's business segments for the years ended December 31, 2011, 2010 and 2009.

(In millions)	Electric Utility	Transportation and Storage	Gathering and Processing	Marketing	Other Operations	Eliminations	Total
2011							
Operating revenues	**$2,211.5**	**$ 410.5**	**$1,167.1**	**$678.0**	**$ –**	**$ (551.2)**	**$3,915.9**
Cost of goods sold	**1,013.5**	**253.3**	**870.7**	**688.1**	**–**	**(547.7)**	**2,277.9**
Gross margin on revenues	**1,198.0**	**157.2**	**296.4**	**(10.1)**	**–**	**(3.5)**	**1,638.0**
Other operation and maintenance	**436.0**	**46.5**	**111.8**	**7.3**	**(17.3)**	**(3.1)**	**581.2**
Depreciation and amortization	**216.1**	**21.6**	**55.6**	**0.4**	**13.4**	**–**	**307.1**
Impairment of assets	**–**	**–**	**6.3**	**–**	**–**	**–**	**6.3**
Gain on insurance proceeds	**–**	**–**	**(3.0)**	**–**	**–**	**–**	**(3.0)**
Taxes other than income	**73.6**	**14.7**	**7.0**	**0.3**	**4.1**	**–**	**99.7**
Operating income (loss)	**$ 472.3**	**$ 74.4**	**$ 118.7**	**$ (18.1)**	**$ (0.2)**	**$ (0.4)**	**$ 646.7**
Total assets	**$6,620.9**	**$1,805.5**	**$1,483.8**	**$ 74.5**	**$166.6**	**$(1,245.3)**	**$8,906.0**
Capital expenditures[(A)]	**$ 844.5**	**$ 39.3**	**$ 572.0**	**$ 1.8**	**$ 13.8**	**$ (0.6)**	**$1,470.8**
2010							
Operating revenues	$2,109.9	$ 403.6	$1,005.6	$798.5	$ –	$ (600.7)	$3,716.9
Cost of goods sold	1,000.2	246.4	733.3	804.7	–	(597.2)	2,187.4
Gross margin on revenues	1,109.7	157.2	272.3	(6.2)	–	(3.5)	1,529.5
Other operation and maintenance	418.1	48.9	91.5	8.4	(13.6)	(3.5)	549.8
Depreciation and amortization	208.7	21.1	50.1	0.1	11.3	–	291.3
Impairment of assets	–	0.7	0.4	–	–	–	1.1
Taxes other than income	69.2	13.9	6.4	0.3	3.6	–	93.4
Operating income (loss)	$ 413.7	$ 72.6	$ 123.9	$ (15.0)	$ (1.3)	$ –	$ 593.9
Total assets	$5,898.1	$1,246.1	$ 973.8	$ 94.5	$135.4	$ (678.8)	$7,669.1
Capital expenditures	$ 631.6	$ 70.2	$ 164.0	$ 2.4	$ 14.1	$ (2.4)	$ 879.9
2009							
Operating revenues	$1,751.2	$ 401.0	$ 657.5	$619.9	$ –	$ (559.9)	$2,869.7
Cost of goods sold	796.3	239.9	458.8	617.7	–	(555.0)	1,557.7
Gross margin on revenues	954.9	161.1	198.7	2.2	–	(4.9)	1,312.0
Other operation and maintenance	348.0	40.9	87.2	9.2	(13.9)	(4.6)	466.8
Depreciation and amortization	187.4	20.4	43.9	0.1	10.8	–	262.6
Impairment of assets	0.3	0.9	1.9	–	–	–	3.1
Taxes other than income	65.1	13.2	5.5	0.4	3.4	–	87.6
Operating income (loss)	$ 354.1	$ 85.7	$ 60.2	$ (7.5)	$ (0.3)	$ (0.3)	$ 491.9
Total assets	$5,478.1	$1,159.5	$ 866.1	$125.2	$137.3	$ (499.5)	$7,266.7
Capital expenditures	$ 600.5	$ 71.4	$ 166.0	$ –	$ 10.2	$ (0.3)	$ 847.8

(A) *Includes $200.4 million related to the acquisition of certain gas gathering assets as discussed in Note 3.*

16. Commitments and Contingencies

Operating Lease Obligations

The Company has operating lease obligations expiring at various dates, primarily for OG&E railcar leases and Enogex noncancellable operating leases. Future minimum payments for noncancellable operating leases are as follows:

(In millions, year ended December 31)	2012	2013	2014	2015	2016	2017 and Beyond	Total
Operating lease obligations							
OG&E railcars	$2.9	$2.9	$2.8	$2.7	$27.4	$ –	$38.7
Enogex noncancellable operating leases	3.9	3.0	2.4	2.4	2.2	0.6	14.5
Total operating lease obligations	$6.8	$5.9	$5.2	$5.1	$29.6	$0.6	$53.2

Payments for operating lease obligations were $9.5 million, $9.4 million and $9.2 million for the years ended December 31, 2011, 2010 and 2009, respectively.

OG&E Railcar Lease Agreement

OG&E has a noncancellable operating lease with purchase options, covering 1,392 coal hopper railcars to transport coal from Wyoming to OG&E's coal-fired generation units. Rental payments are charged to Fuel Expense and are recovered through OG&E's tariffs and fuel adjustment clauses. On December 15, 2010, OG&E renewed the lease agreement effective February 1, 2011. At the end of the new lease term, which is February 1, 2016, OG&E has the option to either purchase the railcars at a stipulated fair market value or renew the lease. If OG&E chooses not to purchase the railcars or renew the lease agreement and the actual fair value of the railcars is less than the stipulated fair market value, OG&E would be responsible for the difference in those values up to a maximum of $22.8 million.

OG&E is also required to maintain all of the railcars it has under lease to transport coal from Wyoming and has entered into agreements with Progress Rail Services and WATCO, both of which are non-affiliated companies, to furnish this maintenance.

Enogex Noncancellable Operating Leases

Enogex currently occupies 116,184 square feet of office space at its executive offices under a lease that expires March 31, 2012. On June 30, 2011, Enogex executed a five-year lease agreement that expires March 31, 2017 for 134,219 square feet of office space at its new executive offices. The lease payments are $11.3 million over the lease term which begins April 1, 2012. Enogex also has compression service and gas treating service agreements which are either on a month-to-month basis or expire during 2012 and 2013.

Other Purchase Obligations and Commitments

The Company's other future purchase obligations and commitments estimated for the next five years are as follows:

Public Utility Regulatory Policy Act of 1978

At December 31, 2011, OG&E has QF contracts having terms of 15 to 32 years. These contracts were entered into pursuant to the Public Utility Regulatory Policy Act of 1978. Stated generally, the Public Utility Regulatory Policy Act of 1978 and the regulations thereunder promulgated by the FERC require OG&E to purchase power generated in a manufacturing process from a QF. The rate for such power to be paid by OG&E was approved by the OCC. The rate generally consists of two components: one is a rate for actual electricity purchased from the QF by OG&E; the other is a capacity charge, which OG&E must pay the QF for having the capacity available. However, if no electrical power is made available to OG&E for a period of time (generally three months), OG&E's obligation to pay the capacity charge is suspended. The total cost of cogeneration payments is recoverable in rates from customers. For the 320 MW AES-Shady Point, Inc. QF contract and the 120 MW PowerSmith Cogeneration Project, L.P. QF contract, OG&E purchases 100 percent of the electricity generated by the QFs.

For the years ended December 31, 2011, 2010 and 2009, OG&E made total payments to cogenerators of $140.7 million, $147.3 million and $139.8 million, respectively, of which $78.0 million, $80.7 million and $83.1 million, respectively, represented capacity payments. All payments for purchased power, including cogeneration, are included in the Consolidated Statements of Income as Cost of Goods Sold.

OG&E Minimum Fuel Purchase Commitments

OG&E purchased necessary fuel supplies of coal and natural gas for its generating units of $647.6 million, $721.4 million and $588.3 million for the years ended December 31, 2011, 2010 and 2009, respectively. OG&E has coal contracts for purchases from January 2012 through

(In millions)	2012	2013	2014	2015	2016	Total
Other purchase obligations and commitments						
OG&E cogeneration capacity and fixed operation and maintenance payments	$ 90.3	$ 89.4	$ 87.3	$ 85.2	$ 83.3	$ 435.5
OG&E expected cogeneration energy payments	59.3	68.9	81.3	74.2	86.8	370.5
OG&E minimum fuel purchase commitments	380.2	192.4	87.9	90.4	–	750.9
OG&E expected wind purchase commitments	32.4	32.8	33.3	34.0	34.7	167.2
OG&E long-term service agreement commitments	4.5	6.6	33.7	5.1	5.0	54.9
OER Cheyenne Plains commitments	5.3	6.5	6.5	1.6	–	19.9
OER MEP commitments	2.1	2.1	1.2	–	–	5.4
OER other commitments	4.9	3.1	3.1	3.1	0.7	14.9
Total other purchase obligations and commitments	$579.0	$401.8	$334.3	$293.6	$210.5	$1,819.2

December 2015. OG&E has natural gas contracts for purchases from January 2012 through March 2012 that account for 26 percent of OG&E's projected 2012 natural gas requirements. Additional gas supplies to fulfill OG&E's remaining 2012 natural gas requirements will be acquired through additional requests for proposal in early to mid-2012, along with monthly and daily purchases, all of which are expected to be made at market prices.

OG&E Wind Purchase Commitments

OG&E's current wind power portfolio includes: (i) the Centennial wind farm, (ii) the OU Spirit wind farm, (iii) the Crossroads wind farm, (iv) access to up to 50 MWs of electricity generated at a wind farm near Woodward, Oklahoma from a 15-year contract OG&E entered into with FPL Energy that expires in 2018, (v) access to up to 150 MWs of electricity generated at a wind farm in Woodward County, Oklahoma from a 20-year contract OG&E entered into with CPV Keenan that expires in 2030 and (vi) access to up to 130 MWs of electricity generated at a wind farm in Woodward County, Oklahoma from a 20-year contract OG&E entered into with Edison Mission Energy that expires in 2030.

The following table summarizes OG&E's wind power purchases for the years ended December 31, 2011, 2010 and 2009.

(In millions, year ended December 31)	2011	2010	2009
CPV Keenan	**$24.5**	$3.8	$ –
Edison Mission Energy	**8.5**	–	–
FPL Energy	**3.7**	3.9	4.0
Total wind power purchased	**$36.7**	$7.7	$4.0

OG&E Long-Term Service Agreement Commitments

In July 2004, OG&E acquired a 77 percent interest in the McClain Plant. As part of that acquisition, OG&E became subject to an existing long-term parts and service maintenance contract for the upkeep of the natural gas-fired combined cycle generation facility. The contract was initiated in December 1999, and runs for the earlier of 96,000 factored-fired hours or 4,800 factored-fired starts. Based on historical usage and current expectations for future usage, this contract is expected to run until 2015. The contract requires payments based on both a fixed and variable cost component, depending on how much the McClain Plant is used.

In September 2008, OG&E acquired a 51 percent interest in the Redbud Plant. As part of that acquisition, OG&E became subject to an existing long-term parts and service maintenance contract for the upkeep of the natural gas-fired combined cycle generation facility. The contract was initiated in January 2001, and runs for the earlier of 120,000 factored-fired hours or 4,500 factored-fired starts. Based on historical usage and current expectations for future usage, this contract is expected to run until 2028. The contract requires payments based on both a fixed and variable cost component, depending on how much the Redbud Plant is used.

OER Agreement with Cheyenne Plains Gas Pipeline Company, L.L.C. (Cheyenne Plains)

In 2004, OER entered into a firm transportation service agreement with Cheyenne Plains, who operates the Cheyenne Plains Pipeline that provides firm transportation services in Wyoming, Colorado and Kansas, for 60,000 decatherms/day of firm capacity on the pipeline. The firm transportation service agreement was for a 10-year term beginning with the in-service date of the Cheyenne Plains Pipeline in March 2005 with an annual demand fee of $7.4 million. Effective March 1, 2007, OER and Cheyenne Plains amended the firm transportation service agreement to provide for OER to turn back 20,000 decatherms/day of its capacity beginning in January 2008 for the remainder of the term.

OER Agreement with MEP

In December 2006, Enogex entered into a firm capacity lease agreement with MEP for a primary term of 10 years (subject to possible extension) that gives MEP and its shippers access to capacity on Enogex's system. The quantity of capacity subject to the MEP lease agreement is currently 272 MMcf/d, with the quantity ultimately to be leased subject to being increased by mutual agreement pursuant to the lease agreement. In 2009, OER entered into a firm transportation service agreement with MEP for 10,000 decatherms/day of firm capacity on the pipeline. The firm transportation service agreement was for a five-year term beginning with the in-service date of the MEP pipeline in June 2009 with an annual demand fee of $2.1 million.

Natural Gas Measurement Cases

Will Price, et al. v. El Paso Natural Gas Co., et al. (Price I). On September 24, 1999, various subsidiaries of OGE Energy were served with a class action petition filed in the District Court of Stevens County, Kansas by Quinque Operating Company and other named plaintiffs alleging the mismeasurement of natural gas on non-Federal lands. On April 10, 2003, the court entered an order denying class certification. On May 12, 2003, the plaintiffs (now Will Price, Stixon Petroleum, Inc., Thomas F. Boles and the Cooper Clark Foundation, on behalf of themselves and other royalty interest owners) filed a motion seeking to file an amended class action petition, and the court granted the motion on July 28, 2003. In its amended petition, OG&E and Enogex Inc. were omitted from the case but two of OGE Energy's other subsidiary entities remained as defendants. The plaintiffs' amended petition seeks class certification and alleges that 60 defendants, including two of OGE Energy's subsidiary entities, have improperly measured the volume of natural gas. The amended petition asserts theories of civil conspiracy, aiding and abetting, accounting and unjust enrichment. In their briefing on class certification, the plaintiffs seek to also allege a claim for conversion. The plaintiffs seek unspecified actual damages, attorneys' fees, costs and pre-judgment and post-judgment interest. The plaintiffs also reserved the right to seek punitive damages.

On September 18, 2009, the court entered its order denying class certification. On October 2, 2009, the plaintiffs filed for a rehearing of the court's denial of class certification. On March 31, 2010, the court denied the plaintiffs' request for rehearing. On July 20, 2011, Enogex LLC and OER filed motions for summary judgment. On January 25, 2012, the court denied portions of the motions for summary judgment related to the legal issue of the plaintiffs' claims regarding civil conspiracy. In an order dated January 23, 2012, the court granted the plaintiffs additional time to perform discovery prior to the consideration of the motions for summary judgment as they relate to the plaintiffs' other claims.

OGE Energy intends to vigorously defend this action. At this time, OGE Energy does not believe the outcome will have a material impact on its financial position.

Will Price, et al. v. El Paso Natural Gas Co., et al. (Price II). On May 12, 2003, the plaintiffs (same as those in the amended petition in Price I above) filed a new class action petition in the District Court of Stevens County, Kansas naming the same defendants and asserting substantially identical legal and/or equitable theories as in the amended petition of the Price I case. OG&E and Enogex Inc. were not named in this case, but two of OGE Energy's other subsidiary entities were named in this case. The plaintiffs allege that the defendants mismeasured the British thermal unit content of natural gas obtained from or measured for the plaintiffs. In their briefing on class certification, the plaintiffs seek to also allege a claim for conversion. The plaintiffs seek unspecified actual damages, attorneys' fees, costs and pre-judgment and post-judgment interest. The plaintiffs also reserved the right to seek punitive damages.

On September 18, 2009, the court entered its order denying class certification. On October 2, 2009, the plaintiffs filed for a rehearing of the court's denial of class certification. On March 31, 2010, the court denied the plaintiffs' request for rehearing. On July 20, 2011, Enogex LLC and OER filed motions for summary judgment. On January 25, 2012, the court denied portions of the motions for summary judgment related to the legal issue of the plaintiffs' claims regarding civil conspiracy. In an order dated January 23, 2012, the court granted the plaintiffs additional time to perform discovery prior to the consideration of the motions for summary judgment as they relate to the plaintiffs' other claims.

OGE Energy intends to vigorously defend this action. At this time, OGE Energy does not believe the outcome will have a material impact on its financial position.

Farris Buser Litigation

On July 22, 2005, Enogex along with certain other unaffiliated co-defendants was served with a purported class action which had been filed on February 7, 2005 by Farris Buser and other named plaintiffs in the District Court of Canadian County, Oklahoma. The plaintiffs own royalty interests in certain oil and gas producing properties and alleged they have been under-compensated by the named defendants, including Enogex and its subsidiaries, relating to the sale of liquid hydrocarbons recovered during the transportation of natural gas from the plaintiffs' wells. The plaintiffs asserted breach of contract, implied covenants, obligation, fiduciary duty, unjust enrichment, conspiracy and fraud causes of action and claim actual damages, plus attorneys' fees and costs, and punitive damages. Enogex and its subsidiaries filed a motion to dismiss which was granted on November 18, 2005, subject to the plaintiffs' right to conduct discovery and the possible re-filing of their allegations in the petition against the Enogex companies. On September 19, 2005, the co-defendants, BP America, Inc. and BP America Production Company filed a cross claim against Enogex Products LLC, wholly-owned subsidiary of Enogex LLC ("Products"), seeking indemnification and/or contribution from Products based upon the 1997 sale of a third-party interest in one of Products natural gas processing plants. On May 17, 2006, the plaintiffs filed an amended petition against Enogex and its subsidiaries. Enogex and its subsidiaries filed a motion to dismiss the amended petition on August 2, 2006. The hearing on the dismissal motion was held on November 20, 2006 and the court denied Enogex's motion. Enogex filed an answer to the amended petition and BP America, Inc. and BP America Production Company's cross claim on January 16, 2007. On October 14, 2011, this case was dismissed without prejudice. While this lawsuit could be re-filed, Enogex considers the claims and cross claim associated with this lawsuit to be without merit, based upon Enogex's investigation to date. Enogex now considers this case closed.

Environmental Laws and Regulations

The activities of OG&E and Enogex are subject to stringent and complex Federal, state and local laws and regulations governing environmental protection including the discharge of materials into the environment. These laws and regulations can restrict or impact OG&E's and Enogex's business activities in many ways, such as restricting the way it can handle or dispose of their wastes, requiring remedial action to mitigate pollution conditions that may be caused by their operations or that are attributable to former operators, regulating future construction activities to mitigate harm to threatened or endangered species and requiring the installation and operation of pollution control equipment. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, the imposition of remedial requirements and the issuance of orders enjoining future operations. OG&E and Enogex believe that their operations are in substantial compliance with current Federal, state and local environmental standards.

Environmental regulation can increase the cost of planning, design, initial installation and operation of OG&E's or Enogex's facilities. Historically, OG&E's and Enogex's total expenditures for environmental control facilities and for remediation have not been significant in relation to its consolidated financial position or results of operations.

The Company believes, however, that it is reasonably likely that the trend in environmental legislation and regulations will continue towards more restrictive standards. Compliance with these standards is expected to increase the cost of conducting business.

On May 17, 2011, OG&E entered into a Consent Order with the ODEQ related to alleged violations of Federal and state opacity standards from 2005 to May 2011 at OG&E's Muskogee and Sooner generating stations. The Consent Order requires OG&E to reach certain milestones with regard to the overall amount of time when opacity exceeds certain amounts. Beginning January 1, 2015, the Consent Order requires each unit at OG&E's Muskogee and Sooner generating stations to have a rolling annual average of the time that opacity emissions are in excess of 20 percent to a level equal to or below one percent of the total time in a measurement period. OG&E agreed to implement two specific projects and other measures as necessary to achieve the milestones established in the Consent Order. These projects and other measures are not expected to involve significant capital or ongoing operating expenses. OG&E also agreed to pay a stipulated cash penalty of $150,000 and agreed to contribute another $150,000 to an ODEQ environmental fund for assisting small Oklahoma communities with their drinking water and wastewater treatment systems. OG&E entered into the Consent Order without admitting or denying the allegations made by the ODEQ. In order to facilitate the court approval of the Consent Order, the ODEQ initiated the necessary legal action against OG&E in state court on May 17, 2011. On June 2, 2011, the Consent Order was approved and entered by the District Court of Oklahoma County, Oklahoma. Subject to the ongoing compliance obligations described above pursuant to the Consent Order, OG&E considers this matter closed.

OG&E and Enogex are managing several significant uncertainties about the scope and timing for the acquisition, installation and operation of additional pollution control equipment and compliance costs for a variety of the EPA rules that are being challenged in court. OG&E and Enogex are unable to predict the financial impact of these matters with certainty at this time. See "Management's Discussion and Analysis of Financial Condition and Results of Operations - Environmental Laws and Regulations" for a discussion of the Company's environmental matters.

Pipeline Safety Legislation

On December 13, 2011, Congress passed the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011, which the President signed into law on January 3, 2012. Among other things, the law requires additional verification of pipeline infrastructure records by Enogex and other intrastate and interstate pipeline owners and operators to confirm the maximum allowable operating pressure of lines located in high consequence areas or more-densely populated areas. Where records are inadequate to confirm the maximum allowable operating pressure, the U.S. Department of Transportation, Pipeline and Hazardous Materials Safety Administration ("PHMSA") will require the operator to re-confirm the maximum allowable operating pressure, a process that could cause temporary or permanent limitations on throughput for affected pipelines. This law requires PHMSA to direct pipeline operators to verify the maximum allowable operating pressure of their pipelines by July 3, 2012, and to submit documentation to PHMSA by July 3, 2013. This law also raises the maximum penalty for violating pipeline safety rules to $0.2 million per violation per day up to $2.0 million for a related series of violations.

In addition, this law requires PHMSA to issue reports and/or, if appropriate, develop new regulations, addressing a variety of subjects, including: (1) requiring pipeline owners and operators to install excess-flow valves in certain circumstances; (2) requiring pipeline owners and operators to use automatic or remote-controlled shut-off valves in certain circumstances; (3) requiring pipeline owners and operators to test to confirm the strength of previously untested transmission lines located within high consequence areas and operating at a pressure greater than 30 percent of specified minimum yield stress; (4) requiring pipeline owners and operators to notify the National Response Center of an accident or incident at the earliest practicable moment (but not later than one hour) after confirming that an accident or incident has occurred; (5) expanding integrity management requirements beyond high consequence areas; and (6) applying the Federal pipeline safety regulations to onshore gathering lines that are not currently subject to the Federal pipeline safety regulations. This law prescribes various deadlines for PHMSA to act on these issues.

At this time, the Company is not able to estimate the capital, operating or other costs that may be required to comply with this law and any related PHMSA regulations that may be promulgated, but such costs could be significant.

Other

In the normal course of business, the Company is confronted with issues or events that may result in a contingent liability. These generally relate to lawsuits, claims made by third parties, environmental actions or the action of various regulatory agencies. When appropriate, management consults with legal counsel and other appropriate experts to assess the claim. If, in management's opinion, the Company has incurred a probable loss as set forth by GAAP, an estimate is made of the loss and the appropriate accounting entries are reflected in the Company's Consolidated Financial Statements. Except as otherwise stated above, in Note 17 below and in Item 3 of the Company's Form 10-K, management, after consultation with legal counsel, does not currently anticipate that liabilities arising out of these pending or threatened lawsuits, claims and contingencies will have a material adverse effect on the Company's consolidated financial position, results of operations or cash flows.

17. Rate Matters and Regulation

Regulation and Rates

OG&E's retail electric tariffs are regulated by the OCC in Oklahoma and by the APSC in Arkansas. The issuance of certain securities by OG&E is also regulated by the OCC and the APSC. OG&E's wholesale electric tariffs, transmission activities, short-term borrowing authorization and accounting practices are subject to the jurisdiction of the FERC. The Secretary of the U.S. Department of Energy has jurisdiction over some of OG&E's facilities and operations. In 2011, 89 percent of OG&E's electric revenue was subject to the jurisdiction of the OCC, eight percent to the APSC and three percent to the FERC.

The OCC issued an order in 1996 authorizing OG&E to reorganize into a subsidiary of OGE Energy. The order required that, among other things, (i) OGE Energy permit the OCC access to the books and records of OGE Energy and its affiliates relating to transactions with OG&E, (ii) OGE Energy employ accounting and other procedures and controls to protect against subsidization of non-utility activities by OG&E's customers and (iii) OGE Energy refrain from pledging OG&E assets or income for affiliate transactions. In addition, the Energy Policy Act of 2005 enacted the Public Utility Holding Company Act of 2005, which in turn granted to the FERC access to the books and records of OGE Energy and its affiliates as the FERC deems relevant to costs incurred by OG&E or necessary or appropriate for the protection of utility customers with respect to the FERC jurisdictional rates.

Completed Regulatory Matters

OG&E Wholesale Agreement

On May 28, 2009, OG&E sent a termination notice to the Arkansas Valley Electric Cooperative that OG&E would terminate its wholesale power agreement to all points of delivery where OG&E sells or has sold power to the Arkansas Valley Electric Cooperative, effective November 30, 2011. In December 2010, OG&E and the Arkansas Valley Electric Cooperative entered into a new wholesale power agreement whereby OG&E will supply wholesale power to the Arkansas Valley Electric Cooperative through June 2015. On January 3, 2011, OG&E submitted this agreement to the FERC for approval. The FERC approved the new wholesale power agreement on March 2, 2011 and the new contract was effective May 1, 2011.

OG&E Crossroads Wind Farm

On July 29, 2010, OG&E received an order from the OCC authorizing OG&E to recover from Oklahoma customers the cost to construct Crossroads, with the rider being implemented as the individual turbines are placed in service. The Crossroads wind farm was fully in service in January 2012. As part of this project, on June 16, 2011, OG&E entered into an interconnection agreement with the SPP for Crossroads which allowed Crossroads to interconnect at 227.5 MWs.

OG&E 2010 Arkansas Rate Case Filing

On September 28, 2010, OG&E filed a rate case with the APSC requesting an annual rate increase of $17.7 million, to recover the cost of significant electric system expansions and upgrades, including high-voltage transmission lines, that have been completed since the last rate filing in August 2008, as well as increased operating costs. OG&E also sought recovery, through a rider, of the Arkansas jurisdictional portion of (i) costs associated with transmission upgrades and facilities that have been approved by the SPP in its regional planning processes and constructed by other non-OG&E transmission owners throughout the SPP that have been allocated to OG&E through the FERC-approved transmission rates and (ii) SPP administrative fees. On June 17, 2011, the APSC approved a settlement agreement among all parties to the case and OG&E implemented new electric rates effective June 20, 2011. Key items of the APSC order include: (i) the recovery of and a return on significant electric system expansions and upgrades, including high-voltage transmission lines, as well as increased operating costs, totaling $8.8 million annually; (ii) authorization for OG&E to recover the actual cost of third-party transmission charges and SPP administrative fees through a rider mechanism which will remain in effect until new rates are implemented after OG&E's next general rate case (the Arkansas jurisdictional portion of the combined costs was $1.0 million in 2011); and (iii) the deferral of certain expenses associated with a customer education program in an amount not to exceed $0.3 million per year for a maximum of two years.

OG&E SPP Cost Tracker

On October 7, 2010, OG&E filed an application with the OCC seeking recovery of the Oklahoma jurisdictional portion of (i) costs associated with transmission upgrades and facilities that have been approved by the SPP in its regional planning processes and constructed by other non-OG&E transmission owners throughout the SPP that have been allocated to OG&E through the FERC-approved transmission rates and (ii) SPP administrative fees. OG&E requested authorization to implement a cost tracker in order to recover from its retail customers the third-party project costs discussed above and to collect its administrative SPP cost assessment levied under Schedule 1A of the SPP open access transmission tariff, which is currently recovered in base rates. OG&E also requested authorization to establish a regulatory asset effective January 1, 2011 in order to give OG&E the opportunity to recover such costs that will be paid but not recovered until the cost tracker is made effective. On February 8, 2011, all parties signed a settlement agreement in this matter which would allow OG&E to recover the costs discussed in (i) above through a recovery rider effective January 1, 2011. OG&E recovered $5.1 million of incremental revenues in 2011 through the rider. Rather than including the costs of the SPP administrative fee assessment in the recovery rider, the stipulating parties agreed to allow OG&E to include the projected 2012 level of the SPP administrative fee assessment in its next Oklahoma rate case which was filed in August

2011. Pursuant to the settlement agreement in OG&E's 2011 Oklahoma general rate case filing, OG&E proposed that recovery in base rates for the costs of transmission projects it constructs and owns and that are authorized by the SPP in its regional planning processes should be limited to the Oklahoma retail jurisdictional share of the costs for such projects allocated to OG&E by the SPP. On March 28, 2011, the OCC issued an order in this matter approving the settlement agreement.

OG&E Fuel Adjustment Clause Review for Calendar Year 2009

On October 29, 2010, the OCC Staff filed an application for a public hearing to review and monitor OG&E's application of the 2009 fuel adjustment clause. On December 28, 2010, OG&E responded by filing the necessary information and documents to satisfy the OCC's minimum filing requirement rules. An intervenor representing a group of OG&E's industrial customers filed testimony on March 11, 2011 seeking a $15.5 million refund related to (i) a purported failure by OG&E to maximize the use of its coal-fired power plants and (ii) an inappropriate extension of the existing gas transportation and storage contract between OG&E and Enogex. OG&E filed rebuttal testimony on April 4, 2011 in opposition to the claims of the intervenor. On August 11, 2011, all parties to this case signed a settlement agreement in this matter, stating that (i) OG&E was prudent in its operations during 2009; (ii) a third party expert should be hired to evaluate OG&E's future gas transportation and storage needs and that OG&E should file a plan for meeting its future gas transportation and storage needs by mid-2012; and (iii) with respect to the existing gas transportation and storage contract with Enogex, OG&E will return $8.4 million to its customers in settlement for all periods under the contract through April 30, 2013. In August 2011, OG&E credited $4.9 million to its customers and will credit the remaining amount on a monthly basis through April 30, 2013. The OCC issued an order approving the settlement agreement on August 29, 2011.

OG&E Smart Grid Project

On December 17, 2010, OG&E filed an application with the APSC requesting pre-approval for system-wide deployment of smart grid technology and a recovery rider, including a credit for the Smart Grid grant awarded by the U.S. Department of Energy under the American Recovery and Reinvestment Act of 2009. On June 22, 2011, OG&E reached a settlement agreement with all the parties in this matter. OG&E and the other parties in this matter agreed to ask the APSC to approve the settlement agreement including the following: (i) pre-approval of system-wide deployment of smart grid technology in Arkansas and authorization for OG&E to begin recovering the prudently incurred costs of the Arkansas system-wide deployment of smart grid technology through a rider mechanism that will become effective in accordance with the order approving the settlement agreement; (ii) cost recovery through the rider would commence when all of the smart meters to be deployed in Arkansas are in service; (iii) OG&E guarantees that customers will receive certain operations and maintenance cost reductions resulting from the smart grid deployment as a credit to the recovery rider; and (iv) the stranded costs associated with OG&E's existing meters which are being replaced by smart meters will be accumulated in a regulatory asset and recovered in base rates beginning after an order is issued in OG&E's next general rate case. OG&E currently expects to spend $14 million, net of funds from the U.S. Department of Energy grant, in capital expenditures to implement smart grid in Arkansas pursuant to the settlement agreement. On August 3, 2011, the APSC issued an order in this matter approving the settlement agreement.

OG&E FERC Transmission Rate Incentive Filing

On February 18, 2011, OG&E submitted to the FERC a request seeking limited transmission rate incentives for five transmission projects. OG&E requested recovery of 100 percent of all prudently incurred construction work in progress in rate base for five 345 kilovolt Extra High Voltage transmission projects to be constructed and owned by OG&E within the SPP's region. OG&E also requested to recover 100 percent of all prudently incurred development and construction costs if the transmission projects are abandoned or cancelled, in whole or in part, for reasons beyond OG&E's control. On April 19, 2011, the FERC granted these incentives for the Sooner-Rose Hill, Sunnyside-Hugo and Balanced Portfolio 3E transmission projects discussed below.

OG&E Pension Tracker Modification Filing

On February 22, 2011, OG&E filed an application with the OCC requesting that OG&E's pension tracker be modified to include the difference between the level of retiree medical costs authorized in OG&E's last rate case and the current level of these expenses as a regulatory liability, effective January 1, 2011. On June 23, 2011, a settlement agreement was filed by parties in the case stating that the pension tracker should be modified as proposed by OG&E and that the level of retiree medical costs included in base rates will be reviewed and determined in OG&E's next rate case. On September 27, 2011, the OCC issued an order in this matter approving the settlement agreement.

OG&E Demand and Energy Efficiency Program Filing

To build on the success of its earlier programs and further promote energy efficiency and conservation for each class of OG&E customers, on March 15, 2011, OG&E filed an application with the APSC seeking approval of several programs, ranging from residential weatherization to commercial lighting. In seeking approval of these programs, OG&E also sought recovery of the program and related costs through a rider that would be added to customers' electric bills. On June 30, 2011, the APSC issued an order approving OG&E's energy efficiency plan for 2011 and approving OG&E's energy efficiency cost recovery rider for 2011. In Arkansas, OG&E's program is expected to cost $7.0 million over a three-year period and is expected to increase the average residential electric bill by $1.47 per month.

FERC Order No. 1000, Final Rule on Transmission Planning and Cost Allocation

On July 21, 2011, the FERC issued Order No. 1000, which revised the FERC's existing regulations governing the process for planning enhancements and expansions of the electric transmission grid in a particular region, along with the corresponding process for allocating the costs of such expansions. Order No. 1000 applies only to "new transmission facilities," which are described as those subject to evaluation or reevaluation (under the applicable local or regional transmission planning process) subsequent to the effective date of the regulatory compliance filings required by the rule, which are expected to be filed during the third quarter of 2012. Order No. 1000 leaves to individual regions to determine whether a previously-approved project is subject to reevaluation and is therefore governed by the new rule.

Order No. 1000 requires, among other things, public utility transmission providers, such as the SPP, to participate in a process that produces a regional transmission plan satisfying certain standards, and requires that each such regional process consider transmission needs driven by public policy requirements (such as state or Federal policies favoring increased use of renewable energy resources). Order No. 1000 also directs public utility transmission providers to coordinate with neighboring transmission planning regions. In addition, Order No. 1000 establishes specific regional cost allocation principles and directs public utility transmission providers to participate in regional and interregional transmission planning processes that satisfy these principles.

On the issue of determining how entities are to be selected to develop and construct the specific transmission projects, Order No. 1000 directs public utility transmission providers to remove from the FERC-jurisdictional tariffs and agreements provisions that establish any federal "right of first refusal" for the incumbent transmission owner (such as OG&E) regarding transmission facilities selected in a regional transmission planning process, subject to certain limitations. However, Order No. 1000 is not intended to affect the right of an incumbent transmission owner (such as OG&E) to build, own and recover costs for upgrades to its own transmission facilities, and Order No. 1000 does not alter an incumbent transmission owner's use and control of existing rights of way. Order No. 1000 also clarifies that incumbent transmission owners may rely on regional transmission facilities to meet their reliability needs or service obligations. The SPP currently has a "right of first refusal" for incumbent transmission owners and this provision has played a role in OG&E being selected by the SPP to build various transmission projects in Oklahoma.

OGE Energy is continuing to evaluate Order No. 1000 and cannot at this time determine its precise impact on OG&E. Nevertheless, at the present time, OGE Energy has no reason to believe that the implementation of Order No. 1000 will impact OG&E's transmission projects currently under development and construction for which OG&E has received a notice to proceed from the SPP.

Enogex FERC Section 311 2007 Rate Case

On October 1, 2007, Enogex made its required triennial rate filing at the FERC to update its Section 311 maximum interruptible transportation rates for Section 311 service in the East Zone and West Zone. Enogex's filing requested an increase in the maximum zonal rates and proposed to place such rates into effect on January 1, 2008. A number of parties intervened and some also filed protests. Enogex did not place the increased rates set forth in its October 2007 rate filing into effect but rather continued to provide interruptible Section 311 service under the maximum Section 311 rates for both zones approved by the FERC in the previous rate case. A final settlement was filed with the FERC on August 5, 2010. With the filing of Enogex's Section 311 2009 rate case discussed below, the rate period for the 2007 rate case became a limited locked-in period from January 2008 through May 2009. On October 13, 2011, the FERC issued an order in this matter approving the settlement agreement, providing that Enogex's rates from its previous rate case remain in effect and that the MEP lease agreement discussed below would be addressed in Enogex's Section 311 2009 rate case. This matter is now closed.

Enogex FERC Section 311 2009 Rate Case

On March 27, 2009, Enogex filed a petition for rate approval with the FERC to set the maximum rates for its new firm East Zone Section 311 transportation service and to revise the rates for its existing East and West Zone interruptible Section 311 transportation service. In anticipation of offering this new service, Enogex had filed with the FERC, as required by the FERC's regulations, a revised Statement of Operating Conditions Applicable to Transportation Services to describe the terms, conditions and operating arrangements for the new service. Enogex made the Statement of Operating Conditions filing on February 27, 2009. Enogex began offering firm East Zone Section 311 transportation service on April 1, 2009. The revised East and West Zone zonal rates for the Section 311 interruptible transportation service became effective June 1, 2009. The rates for the firm East Zone Section 311 transportation service and the increase in the rates for East and West Zone and interruptible Section 311 service were collected, subject to refund, pending the FERC approval of the proposed rates. A number of parties intervened in both the rate case and the Statement of Operating Conditions filing and some additionally filed protests. On January 4, 2010, the FERC Staff submitted an offer proposing various adjustments to Enogex's filed cost of service. On April 27, 2010, Enogex submitted comments to the FERC Staff stating that it would agree to the offer, contingent upon all parties agreeing to support or not oppose. On October 4, 2011, Enogex filed a settlement agreement with the FERC which included a proposed refund to shippers of $2.1 million related to the increase in the rates for East and West Zone and interruptible Section 311 service which were collected, subject to refund, pending the FERC approval of the proposed rates. This refund was made to shippers in January 2012. On December 16, 2011, the FERC issued an order approving the settlement agreement. Also, as discussed below, the MEP lease agreement was addressed in this rate case.

On November 13, 2007, one of the protesting intervenors filed to consolidate the Enogex 2007 rate case with a separate Enogex application pending before the FERC allowing Enogex to lease firm capacity to MEP and with separate applications filed by MEP with the FERC for a certificate to construct and operate the MEP pipeline and to lease firm capacity from Enogex. Enogex and MEP separately opposed this intervenor's protests and assertions in its initial and subsequent pleadings. On July 25, 2008, the FERC issued an order (i) approving the MEP project including the approval of a limited jurisdiction certificate and (ii) authorizing the Enogex lease agreement with MEP. Accordingly, Enogex proceeded with the construction of facilities necessary to implement this service. On August 25, 2008, a protestor sought rehearing which the FERC denied. Enogex commenced service to MEP under the lease agreement on June 1, 2009. On July 16, 2009, the protestor filed, with the United States Court of Appeals for the District of Columbia Circuit, a petition for review of the FERC's orders approving the MEP construction and the MEP lease of capacity from Enogex requesting that such orders be modified or set aside on the grounds that they are arbitrary, capricious and contrary to law. On December 28, 2010, the Court of Appeals issued an opinion generally upholding the FERC's orders, but remanding the case for further explanation of one aspect of the FERC's reasoning. The Court of Appeals emphasized that it was not vacating the FERC's orders and that its approval of the Enogex lease agreement with MEP remains in effect and legally binding. On remand, the FERC was to clarify that its decision was based on a finding that the lease does not adversely affect existing customers on Enogex's system. On January 21, 2011, Apache Corporation filed a motion asking the FERC to establish procedures on remand and to either condition the lease on Enogex's willingness to provide firm Section 311 transportation service to existing customers on all portions of its system or to establish an expedited briefing schedule. On February 7, 2011, Enogex, MEP and Chesapeake Energy Corporation filed a joint answer asking the FERC to find, among other things, that the reduction in the amount of interruptible transportation capacity available due to the MEP lease did not have an adverse affect on Apache Corporation and to acknowledge that Apache Corporation's request to condition the lease on the provision of West Zone 311 firm transportation service has been addressed as Enogex filed a rate case on January 28, 2011 proposing to implement such service effective March 1, 2011. On March 1, 2011, Apache Corporation filed an answer seeking to refute some of the arguments presented in the joint answer filed by Enogex, MEP and Chesapeake Energy Corporation. On March 3, 2011, the FERC issued an order on remand affirming the authorizations previously granted to Enogex and MEP and clarifying the applicable legal standard in response to the court's directive. On April 4, 2011, Apache Corporation filed a request for rehearing of the FERC's order on remand. On September 29, 2011, the FERC issued an order denying Apache Corporation's motion for rehearing. Apache Corporation did not appeal the FERC's March 3, 2011 order on remand and/or the September 29, 2011 order denying rehearing. This matter is now closed.

Pending Regulatory Matters

OG&E 2011 Oklahoma Rate Case Filing

As part of the Joint Stipulation and Settlement Agreement reached in OG&E's 2009 Oklahoma rate case filing, the parties agreed that OG&E would file a rate case on or before June 30, 2011. On May 27, 2011, OG&E requested an extension until the end of July 2011 for filing the Oklahoma rate case. On July 28, 2011, OG&E filed its application with the OCC requesting an annual rate increase of $73.3 million, or a 4.3 percent increase in its rates. OG&E is requesting a return on equity of 11.00 percent based on a common equity percentage of 53 percent. Each 0.10 percent change in the requested return on equity affects the requested rate increase by $3.0 million. In its application, OG&E seeks to recover increases in its operating costs and to begin earning on approximately $500 million of new capital investments made on behalf of its Oklahoma customers during the previous two and one-half years. On November 9, 2011, the OCC Staff recommended a $6.2 million annual rate decrease based on a return on equity of 9.81 percent and a common equity percentage of 53 percent. The staff of the Oklahoma Attorney General recommended a return on equity of 9.818 percent and a common equity percentage of 49.5 percent. The staff of the Oklahoma Attorney General did not recommend a specific revenue requirement, but OG&E believes that adoption of the staff of the Oklahoma Attorney General's recommendations would result in a rate decrease. The Oklahoma Industrial Electric Consumers recommended a $56 million annual rate decrease based on a return on equity of 9.5 percent and a common equity percentage of 48 percent. OG&E filed rebuttal testimony on November 29, 2011 on the revenue requirement testimony filed by the parties on November 9, 2011. On November 16, 2011, the parties filed cost-of-service and rate design testimony and OG&E filed rebuttal testimony in those areas on December 2, 2011. The hearing in this matter began on December 13, 2011. OG&E expects to receive an order from the OCC in the first quarter of 2012.

OG&E Fuel Adjustment Clause Review for Calendar Year 2010

On August 19, 2011, the OCC Staff filed an application for a public hearing to review and monitor OG&E's application of the 2010 fuel adjustment clause. On October 18, 2011, OG&E responded by filing the necessary information and documents to satisfy the OCC's minimum filing requirement rules. A procedural schedule has not yet been established in this matter.

OG&E Contract and Wind Energy Purchase Agreement Filing

On December 1, 2011, OG&E filed an application with the OCC requesting approval of a 20-year agreement that is intended to provide wind power to help meet the current and future power generation needs of Oklahoma State University. The project calls for OG&E to contract with NextEra Energy to build a 60 MW wind farm near Blackwell, Oklahoma, to support the Oklahoma State University project in which NextEra will build, own and operate the wind farm and OG&E will purchase the electric output. A procedural schedule has not yet been established in this matter. OG&E expects to receive a decision from the OCC in the first quarter of 2012.

SPP Transmission/Substation Projects

The SPP is a regional transmission organization under the jurisdiction of the FERC that was created to ensure reliable supplies of power, adequate transmission infrastructure and competitive wholesale prices of electricity. The SPP does not build transmission though the SPP's tariff contains rules that govern the transmission construction process. Transmission owners complete the construction and then own, operate and maintain transmission assets within the SPP region. When the SPP Board of Directors approves a project, the transmission provider in the area where the project is needed currently has the first obligation to build; however, the process for deciding which entity constructs and owns a project may change as a result of FERC Order. No. 1000 discussed above.

There are several studies currently under review at the SPP including a 20-year plan to address issues of regional and interregional importance. The 20-year plan suggests overlaying the SPP footprint with a 345 kilovolt transmission system and integrating it with neighboring regional entities. In 2009, the SPP Board of Directors approved a new report that recommended restructuring the SPP's regional planning processes to focus on the construction of a robust transmission system, large enough in both scale and geography, to provide flexibility to meet the SPP's future needs. OG&E expects to actively participate in the ongoing study, development and transmission growth that may result from the SPP's plans.

In 2007, the SPP notified OG&E to construct 44 miles of a new 345 kilovolt transmission line which will originate at OG&E's existing Sooner 345 kilovolt substation and proceed generally in a northerly direction to the Oklahoma/Kansas Stateline (referred to as the Sooner-Rose Hill project). At the Oklahoma/Kansas Stateline, the line will connect to the companion line being constructed in Kansas by Westar Energy. Construction of the line began in early 2011 and the line is estimated to be in service by mid-2012 at an estimated cost of $45 million for OG&E.

In January 2009, OG&E received notification from the SPP to begin construction on 50 miles of a new 345 kilovolt transmission line and substation upgrades at OG&E's Sunnyside substation, among other projects. In April 2009, Western Farmers Electric Cooperative assigned to OG&E the construction of 50 miles of line designated by the SPP to be built by Western Farmers Electric Cooperative. The new line will extend from OG&E's Sunnyside substation near Ardmore, Oklahoma, 123.5 miles to the Hugo substation owned by Western Farmers Electric Cooperative near Hugo, Oklahoma. The project cost is estimated at $155 million for OG&E. OG&E began preliminary line routing and acquisition of rights-of-way in June 2009. Construction began in January 2011. When construction is completed, which is expected in mid-2012, the SPP will allocate a portion of the annual revenue requirement to OG&E customers according to the regional cost allocation mechanism as provided in the SPP tariff for application to such improvements.

On April 28, 2009, the SPP approved the Balanced Portfolio 3E projects. Balanced Portfolio 3E includes four projects to be built by OG&E and includes: (i) construction of 135 miles of transmission line from OG&E's Seminole substation in a northeastern direction to OG&E's Muskogee substation at an estimated cost of $160 million for OG&E, which is expected to be in service by late 2013, (ii) construction of 96 miles of transmission line from OG&E's Woodward District Extra High Voltage substation in a southwestern direction to the Oklahoma/Texas Stateline to a companion transmission line to be built by Southwestern Public Service to its Tuco substation at an estimated cost of $145 million for OG&E, which is expected to be in service by mid-2014, (iii) construction of 39 miles of transmission line from OG&E's Sooner substation in an eastern direction to the Grand River Dam Authority Cleveland substation at an estimated cost of $60 million for OG&E, which is expected to be in service by late 2012 and (iv) construction of a new substation near Anadarko which consisted of a 345/138 kilovolt transformer and substation breakers and was built in OG&E's portion of the Cimarron-Lawton East Side 345 kilovolt line at an estimated cost of $15 million for OG&E, which was placed in service in December 2011. On June 19, 2009, OG&E received a notice to construct the Balanced Portfolio 3E projects from the SPP. On July 23, 2009, OG&E responded to the SPP that OG&E will construct the Balanced Portfolio 3E projects discussed above beginning in early 2011.

On April 27, 2010, the SPP approved, contingent upon approval by the FERC of a regional cost allocation methodology filed with the FERC by the SPP, a set of transmission projects titled "Priority Projects." The Priority Projects consist of several transmission projects, two of which have been assigned to OG&E. The 345 kilovolt projects include: (i) construction of 99 miles of transmission line from OG&E's Woodward District Extra High Voltage substation to a companion transmission line to be built by Southwestern Public Service to its Hitchland substation in the Texas Panhandle at an estimated cost of $185 million for OG&E, which is expected to be in service by mid-2014 and (ii) construction of 77 miles of transmission line from OG&E's Woodward District Extra High Voltage substation to a companion transmission line at the Kansas border to be built by either Mid-Kansas Electric Company or another company assigned by Mid-Kansas Electric Company at an estimated cost of $150 million to OG&E, which is expected to be in service by late 2014. On June 17, 2010, the FERC approved the cost allocation filed by the SPP and notices to construct these Priority Projects were issued by the SPP on June 30, 2010. On September 27, 2010, OG&E responded to the SPP that OG&E will construct the Priority Projects discussed above beginning in June 2012. The scope of the Woodward District Extra High Voltage substation/Kansas border Priority Project was subsequently revised and the SPP Board of Directors approved this revision in October 2010. The SPP issued a revised notice to construct for this Priority Project on November 22, 2010. On February 4, 2011, OG&E responded to the SPP that OG&E will construct the revised Priority Project.

The capital expenditures related to the Sooner-Rose Hill, Sunnyside-Hugo, Balanced Portfolio 3E and Priority Projects are presented in the summary of capital expenditures for known and committed projects in "Management's Discussion and Analysis of Financial Condition and Results of Operations – Liquidity and Capital Resources – Future Capital Requirements and Financing Activities."

Enogex Storage Statement of Operating Conditions Filing

On August 31, 2010, Enogex filed via eTariff with the FERC a new Statement of Operating Conditions applicable to storage services that replaced Enogex's existing storage Statement of Operating Conditions effective July 30, 2010. Among other things, the new storage Statement of Operating Conditions updates the general terms and conditions for providing storage services. A FERC order is pending.

Enogex FERC Section 311 2011 Rate Case

On January 28, 2011, Enogex submitted a new rate filing to the FERC to set the maximum rate for a new firm Section 311 transportation service in the West Zone of its system and to revise the currently effective maximum rates for Section 311 interruptible transportation service in the East Zone and West Zone. Along with establishing the rate for a new firm service in the West Zone, Enogex's filing requested a decrease in the maximum interruptible zonal rates in the West Zone and to retain the currently effective rates for firm and interruptible services in the East Zone. Enogex reserved the right to implement the higher rates for firm and interruptible services in the East Zone supported by the cost of service to the extent an expeditious settlement agreement cannot be reached in the proceeding. Enogex proposed that the rates be placed into effect on March 1, 2011. The deadline for interventions and protests on Enogex's filing was November 28, 2011 and no protests were filed. On January 10, 2012, Enogex filed a settlement agreement with the FERC. The deadline for comments to the filing was January 17, 2012, and no comments opposing the settlement were filed. A FERC order is pending.

Enogex 2011 Fuel Filing

On February 28, 2011, Enogex submitted its annual fuel filing to establish the fixed fuel percentages for its East Zone and West Zone for the upcoming fuel year (April 1, 2011 through March 31, 2012). Along with the revised fuel percentages, Enogex also requested authority to revise its Statement of Operating Conditions to permanently change the annual filing date to February 28. The deadline for interventions and protests on Enogex's filing was March 15, 2011, and no protests were filed. A FERC order is pending.

18. Quarterly Financial Data (Unaudited)

Due to the seasonal fluctuations and other factors of the Company's businesses, the operating results for interim periods are not necessarily indicative of the results that may be expected for the year. In the Company's opinion, the following quarterly financial data includes all adjustments, consisting of normal recurring adjustments, necessary to fairly present such amounts. Summarized consolidated quarterly unaudited financial data is as follows:

(In millions, except per share data, quarter ended)	March 31	June 30	September 30	December 31	Total
Operating revenues					
2011	**$840.5**	**$978.1**	**$1,212.1**	**$885.2**	**$3,915.9**
2010	$875.8	$887.2	$1,125.4	$828.5	$3,716.9
Operating income					
2011	**$ 67.9**	**$182.2**	**$ 299.7**	**$ 96.9**	**$ 646.7**
2010	$ 86.8	$151.5	$ 274.2	$ 81.4	$ 593.9
Net income					
2011	**$ 29.7**	**$109.3**	**$ 181.4**	**$ 43.2**	**$ 363.6**
2010	$ 25.2	$ 77.9	$ 163.5	$ 33.8	$ 300.4
Net income attributable to OGE Energy					
2011	**$ 24.8**	**$103.0**	**$ 178.7**	**$ 36.4**	**$ 342.9**
2010	$ 24.2	$ 77.3	$ 163.1	$ 30.7	$ 295.3
Basic earnings per average common share attributable to OGE Energy common shareholders[(A)]					
2011	**$ 0.25**	**$ 1.05**	**$ 1.82**	**$ 0.37**	**$ 3.50**
2010	$ 0.25	$ 0.79	$ 1.67	$ 0.32	$ 3.03
Diluted earnings per average common share attributable to OGE Energy common shareholders[(A)]					
2011	**$ 0.25**	**$ 1.04**	**$ 1.80**	**$ 0.37**	**$ 3.45**
2010	$ 0.25	$ 0.78	$ 1.65	$ 0.31	$ 2.99

[(A)] *Due to the impact of dilution on the earnings per share calculation, quarterly earnings per share amounts may not add to the total.*

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Stockholders
OGE Energy Corp.

We have audited the accompanying consolidated balance sheets and statements of capitalization of OGE Energy Corp. as of December 31, 2011 and 2010, and the related consolidated statements of income, changes in stockholders' equity, comprehensive income and cash flows for each of the three years in the period ended December 31, 2011. These financial statements are the responsibility of the company's management. Our responsibility is to express an opinion on these financial statements 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 audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of OGE Energy Corp. at December 31, 2011 and 2010, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2011, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), OGE Energy Corp.'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 and our report dated February 16, 2012 expressed an unqualified opinion thereon.

Ernst + Young LLP

Ernst & Young LLP
Oklahoma City, Oklahoma
February 16, 2012

CONTROLS AND PROCEDURES

The Company maintains a set of disclosure controls and procedures designed to ensure that information required to be disclosed by the Company in reports that it files or submits under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission rules and forms. In addition, the disclosure controls and procedures ensure that information required to be disclosed is accumulated and communicated to management, including the chief executive officer and chief financial officer, allowing timely decisions regarding required disclosure. As of the end of the period covered by this report, based on an evaluation carried out under the supervision and with the participation of the Company's management, including the chief executive officer and chief financial officer, of the effectiveness of the Company's disclosure controls and procedures (as such term is defined in Rules 13a-15(e) and 15(d)-15(e) under the Securities Exchange Act of 1934), the chief executive officer and chief financial officer have concluded that the Company's disclosure controls and procedures are effective.

No change in the Company's internal control over financial reporting has occurred during the Company's most recently completed fiscal quarter that has materially affected, or is reasonably likely to materially affect, the Company's internal control over financial reporting (as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934).

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The management of the Company is responsible for establishing and maintaining adequate internal control over financial reporting. The Company's internal control system was designed to provide reasonable assurance to the Company's management and Board of Directors regarding the preparation and fair presentation of published financial statements. All internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation.

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, it used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in Internal Control-Integrated Framework. Based on our assessment, we believe that, as of December 31, 2011, the Company's internal control over financial reporting is effective based on those criteria.

The Company's independent auditors have issued an attestation report on the Company's internal control over financial reporting. This report appears on the following page.

Peter B. Delaney

Peter B. Delaney
Chairman of the Board,
President and
Chief Executive Officer

Scott Forbes

Scott Forbes
Controller and
Chief Accounting Officer

Sean Trauschke

Sean Trauschke
Vice President and
Chief Financial Officer

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Stockholders
OGE Energy Corp.

We have audited OGE Energy Corp.'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 (the COSO criteria). OGE Energy Corp.'s management is responsible 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's Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the company's internal control over financial reporting based on our audit.

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

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, OGE Energy Corp. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2011, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets and statements of capitalization of OGE Energy Corp. as of December 31, 2011 and 2010, and the related consolidated statements of income, changes in stockholders' equity, comprehensive income and cash flows for each of the three years in the period ended December 31, 2011 of OGE Energy Corp. and our report dated February 16, 2012 expressed an unqualified opinion thereon.

Ernst & Young LLP

Ernst & Young LLP
Oklahoma City, Oklahoma
February 16, 2012

HISTORICAL PERFORMANCE

(In millions except per share data)	2011	2010	2009	2008	2007
Selected Financial Data					
Operating revenues	**$3,915.9**	$3,716.9	$2,869.7	$ 4,070.7	$ 3,797.6
Cost of goods sold	**2,277.9**	2,187.4	1,557.7	2,818.0	2,634.7
Gross margin on revenues	**1,638.0**	1,529.5	1,312.0	1,252.7	1,162.9
Other operating expenses	**991.3**	935.6	820.1	790.6	707.6
Operating income	**646.7**	593.9	491.9	462.1	455.3
Interest income	**0.5**	–	1.4	6.7	2.1
Allowance for equity funds used during construction	**20.4**	11.4	15.1	–	–
Other income	**19.3**	13.7	27.5	15.4	17.4
Other expense	**21.7**	17.9	16.3	25.6	22.7
Interest expense	**140.9**	139.7	137.4	120.0	90.2
Income tax expense	**160.7**	161.0	121.1	101.2	116.7
Net income	**363.6**	300.4	261.1	237.4	245.2
Less: net income attributable to noncontrolling interest	**20.7**	5.1	2.8	6.0	1.0
Net income attributable to OGE Energy	**$ 342.9**	$ 295.3	$ 258.3	$ 231.4	$ 244.2
Diluted earnings per average common share	**$ 3.45**	$ 2.99	$ 2.66	$ 2.49	$ 2.64
Long-term debt	**$2,737.1**	$2,362.9	$2,088.9	$ 2,161.8	$ 1,344.6
Total assets	**$8,906.0**	$7,669.1	$7,266.7	$ 6,518.5	$ 5,237.8
Common Stock Statistics					
Dividends paid per share	**$ 1.50**	$ 1.45	$ 1.42	$ 1.39	$ 1.36
Dividends declared per share	**$ 1.5175**	$ 1.4625	$ 1.4275	$ 1.3975	$ 1.3675
Book value	**$ 28.76**	$ 24.95	$ 21.06	$ 20.28	$ 18.31
Market price – year end	**$ 56.71**	$ 45.54	$ 36.89	$ 25.78	$ 36.29
Price/earnings ratio – year end	**16.4**	15.3	13.9	10.3	13.6
Basic average shares outstanding (millions)	**97.9**	97.3	96.2	92.4	91.7
Diluted average shares outstanding (millions)	**99.2**	98.9	97.2	92.8	92.5
Actual shares outstanding (millions)	**98.1**	97.6	97.0	93.5	91.8
Number of shareholders	**19,948**	20,942	21,971	22,705	23,983
Capitalization Ratios[A]					
Common equity	**50.7%**	50.4%	46.4%	47.0%	55.7%
Long-term debt	**49.3%**	49.6%	53.6%	53.0%	44.3%
Miscellaneous Statistics					
Electric customers	**789,146**	782,558	776,550	770,088	762,234
Megawatt-hour sales (millions)	**29.5**	28.1	26.9	28.2	27.1
Megawatt generating capability – year end (thousands)	**6.8**	6.5	6.6	6.8	6.2
Megawatt peak demand (thousands)	**7.1**	6.6	6.4	6.5	6.3
Fuel mix (generation only, by kilowatt-hours generated)					
Natural gas	**39%**	42%	38%	30%	36%
Coal	**58%**	55%	60%	68%	62%
Wind	**3%**	3%	2%	2%	2%
Cost (in kilowatt-hours – cents)					
Natural gas	**$ 4.328**	$ 4.638	$ 3.696	$ 8.455	$ 6.872
Coal	**$ 2.064**	$ 1.911	$ 1.747	$ 1.153	$ 1.143
Weighted average	**$ 2.897**	$ 3.012	$ 2.474	$ 3.337	$ 3.173
Total gas throughput volumes (TBtu/d)[B]	**1.94**	1.72	1.79	1.57	1.52
Total natural gas processed (TBtu/d)	**0.79**	0.82	0.70	0.66	0.57
Total natural gas liquids sold (million gallons)	**685**	688	493	426	385
Average sales price per gallon	**$ 1.16**	$ 0.96	$ 0.77	$ 1.26	$ 1.05
Average natural gas sales price per MMBtu[C]	**$ 4.08**	$ 4.24	$ 3.37	$ 7.23	$ 6.15

[A] *Capitalization ratios = [Stockholders' equity/(Stockholders' equity + Long-term debt + Long-term debt due within one year)] and [(Long-term debt + Long-term debt due within one year)/(Stockholders' equity + Long-term debt + Long-term debt due within one year)].*

[B] *Trillion British thermal units per day.*

[C] *Million British thermal unit.*

INVESTOR INFORMATION

Annual Meeting

The annual meeting of shareholders is scheduled for 10 a.m. Thursday, May 17, 2012, at the Skirvin Hilton Hotel, 1 Park Avenue, Oklahoma City. The Board of Directors will request proxies for this meeting and statements will be mailed to shareholders on or about March 30, 2012.

Ticker Symbol Information

The New York Stock Exchange lists OGE Energy Corp. common stock for trading under the symbol OGE. Quotes appear in daily newspapers where the common stock is listed as "OGE Engy" in the New York Stock Exchange table.

Stock Exchange Listing

New York Stock Exchange
OGE Energy Corp.
Common stock

Form 10-K

A copy of the Annual Report to the Securities and Exchange Commission, Form 10-K, will be furnished without charge to any shareholder upon written request by contacting:

Todd Tidwell
OGE Energy Corp.
Investor Relations, MC 1105
P.O. Box 321
Oklahoma City, OK 73101-0321

Shareholder Information

Shareholders with questions or in need of assistance concerning their OGE stock accounts should contact OGE's registrar, stock plan administrator, transfer agent and dividend disbursing agent:

Computershare
P.O. Box 358035
Pittsburgh, PA 15252-8035
Phone toll free: 1-888-216-8114
Internet account access:
www.oge.com

Additional Information

Shareholders, analysts, brokers and institutional investors with questions or comments may contact Todd Tidwell, Director, Investor Relations at (405) 553-3966.

Stock Purchase Plan

This plan offers a convenient and economical way to purchase OGE Energy Corp. common stock. Plan materials are available on the Internet at www.oge.com or a prospectus and enrollment packet may be obtained by calling 1-866-353-7849. Please read the prospectus thoroughly before enrolling in the plan.

Market Price of Common Stock

The following table gives information with respect to price ranges, as reported in *The Wall Street Journal* as New York Stock Exchange Composite Transactions, for the periods shown.

	High	Low
2012		
First Quarter (through February 29)	$57.54	$51.57
2011		
First Quarter	$50.61	$44.69
Second Quarter	53.50	47.64
Third Quarter	52.15	40.56
Fourth Quarter	57.17	45.70
2010		
First Quarter	$39.32	$34.92
Second Quarter	42.25	33.87
Third Quarter	41.11	35.38
Fourth Quarter	46.18	39.93

The number of record holders of the Company's Common Stock at February 29, 2012, was 19,789. The reported closing market price of the Company's Common Stock on the New York Stock Exchange on February 29, 2012, was $52.48.

Dividend Direct Deposit

Shareholders may have their dividends deposited directly into their checking, savings or money market accounts. To take advantage of this service, please contact the registrar.

Duplicate Annual Reports

Annual reports are typically mailed for each separate shareholder registration. To eliminate duplicate mailings please contact the registrar.

Corporate Governance

All of OGE Energy Corp.'s corporate governance material, including codes of conduct, guidelines for corporate governance and committee charters, is available for public viewing on the OGE Energy web site at www.oge.com under the heading "Investor Relations," "Corporate Governance." OGE Energy Corp.'s corporate governance material also is available upon request sent to OGE Energy Corp.'s Corporate Secretary.

Design: Coates and Coates. Photography: John Jernigan. Printing: Southwestern.

OGE Energy Corp. employees are consistently generous contributors to the United Way. In 2011, our company's employees pledged nearly $860,000 to United Way campaigns in communities where they live and work.

OG&E P.O. Box 321 Oklahoma City, Oklahoma 73101-0321 (405) 553-3000