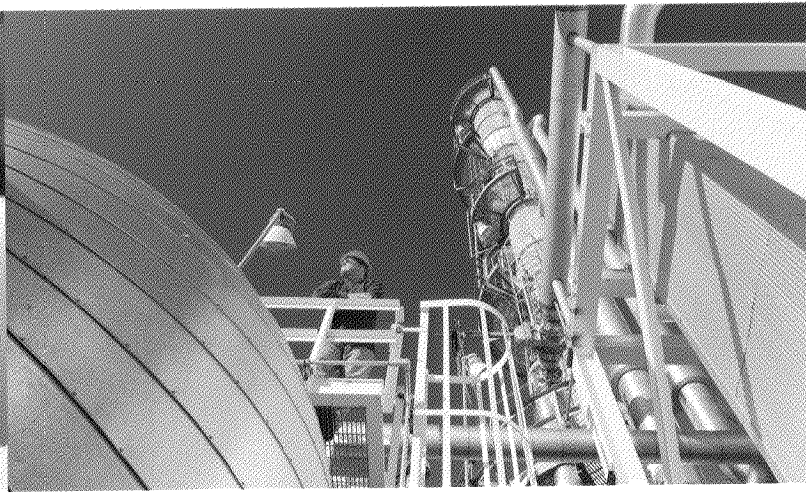
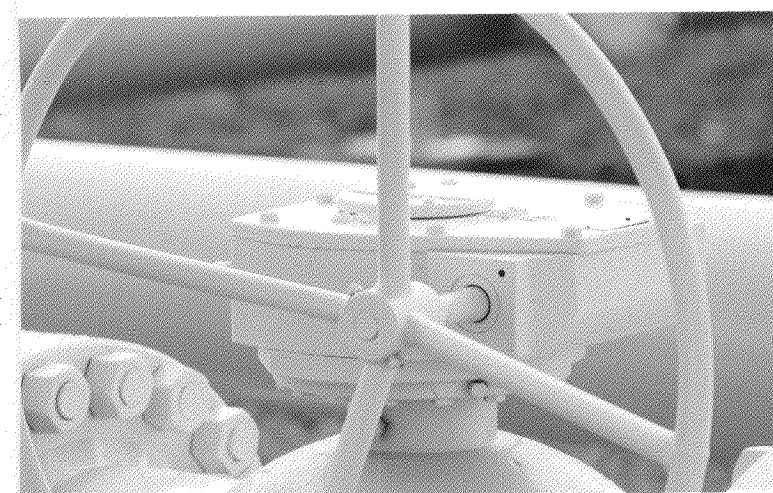
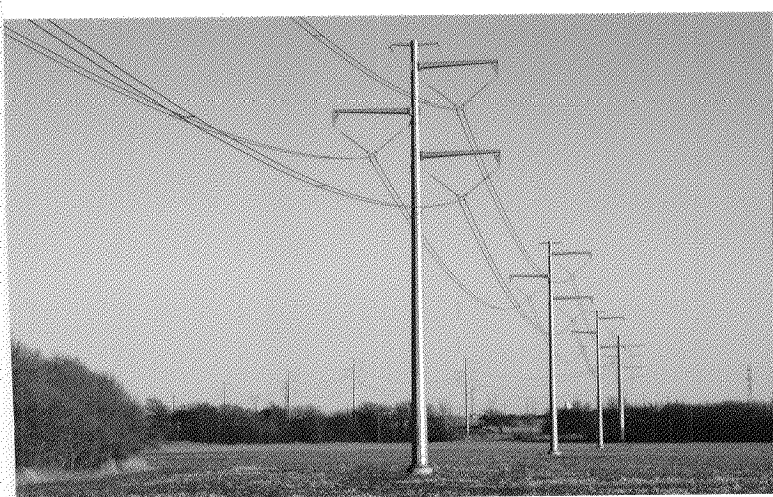


Looking Ahead. Acting Now.



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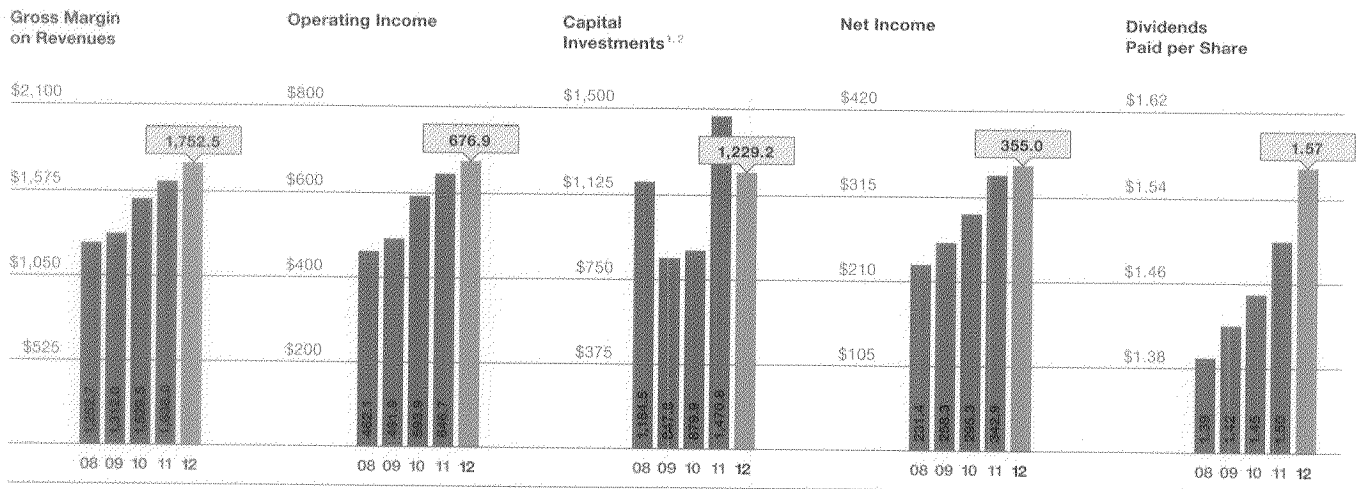
2012 Annual Report

**THIS IS OGE**

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 (Enogex), a midstream natural gas pipeline business. OGE Energy and its subsidiaries have approximately 3,400 employees.

**2012 Highlights**

Dollars in millions unless noted



<sup>1</sup> Includes \$200.4 million related to the acquisition of certain gas gathering assets in 2011.  
<sup>2</sup> Includes \$78.6 million related to the acquisition of certain gas gathering assets in 2012.

**Oklahoma Gas and Electric Company**

Oklahoma Gas and Electric Company serves approximately 798,000 retail customers in Oklahoma and western Arkansas. OG&E, with approximately 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 and storage. The system includes about 8,900 miles of pipe, nine natural gas processing plants and 24 billion cubic feet of natural gas storage capacity.

## WHAT WE SAID; WHAT WE DID

---

### CONSISTENT EARNINGS GROWTH

**What we said:** "We're focused on achieving our long-term earnings growth target of 5 – 7 percent to provide premium valuation for our shareholders."

– 2011 Annual Report, page 3

**What we did:** Since 2009, we've had a compound annual growth rate of 9.6 percent. We understand the importance of consistent earnings growth, and in doing what's necessary to reduce earnings volatility.

---

### INVESTING FOR THE FUTURE

**What we said:** "We are working on other high-voltage transmission lines, including some on the Southwest Power Pool's list of projects to ensure the reliability of the regional power grid."

– 2009 Annual Report, page 15

**What we did:** OG&E's transmission investment now totals nearly \$1.5 billion. We completed two high-voltage transmission lines in 2012 totaling 168 miles, and we currently have 400 miles of high-voltage transmission projects, totaling about \$625 million, at various stages of construction.

---

### LEVERAGING TECHNOLOGY

**What we said:** "With the new [smart] meters, we're lowering our costs and providing customers access to new technology that will help them save money and reduce peak electricity demand."

– 2011 Annual Report, page 8

**What we did:** OG&E saved \$13.5 million in operational costs, including avoided truck rolls and automated connects & disconnects. By the end of 2012, nearly 45,000 customers had enrolled in SmartHours®, which shaved 66 megawatts of peak demand off our system.

---

### ENOGEX GROWTH

**What we said:** "We believe our strong working relationships with natural gas producers, combined with funding for projects from ArcLight, our equity partner, will create new avenues to expand our midstream business."

– 2010 Annual Report, page 3

**What we did:** Since 2010, Enogex has closed two significant acquisitions that added more than 600,000 net acres of long-term commitments, which increased our overall to 2.5 million net acres, primarily located in the Granite Wash, Cleveland Sands, Tonkawa and Cana Woodford plays.

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## Letter To Shareholders.

**The position of strength on which your company stands is no accident. It's the result of conservative business practices and a constant, thoughtful plan for our future. It has been built by our employees' unflinching commitment to safety, reliability, operational excellence and innovation. Sustaining our position requires constant engagement and an intense focus on all areas of our business – operations, finances and culture. More importantly, it requires a drive to achieve more.**

In 2012, OGE Energy Corp. continued the march toward our vision of being an industry leader. We encountered some headwinds – a challenging rate case settlement for OG&E and ongoing low natural gas prices at Enogex – but stayed true to our plan and had another solid year. However, we are not content to rest on our laurels. The stakes are too high. *We are looking ahead, acting now.*

**Financial Strength** OGE is in a position of strength with strong credit ratings, and a conservative but growing dividend that affords us cash flow for future investments. We have grown consolidated earnings 36 percent since 2007, and have increased the dividend for seven consecutive years.

In 2012, we proudly accepted the Edison Electric Institute's Index Award for highest shareholder return among large-cap companies, thanks to a 103 percent return for the five-year period ending Sept. 30, 2012.

That achievement comes in part from thoughtful capital investment and our persistent focus on managing our operations and maintenance expenses. We are optimizing everything from our workforce to our processes, with a goal of keeping O&M growth in check with inflation.

**A Balanced Commitment** At OG&E, we have maintained a diverse generation mix, balancing our commitment to renewable energy with our commitment to provide our customers reasonably priced electricity. Our goal is to defer the construction of incremental fossil fuel generation until at least 2020, and we're accomplishing that by combining our renewable energy program with concurrent efforts to reduce peak demand. Our completed deployment of more than 800,000 smart meters, along with our SmartHours® variable peak pricing plan, empower our customers to better manage their own energy use. That, along with other demand-response programs, provided 77 megawatts of energy

savings in 2012. In addition, we have completed more than 326 miles of high-voltage transmission, which increases reliability and has the potential to lower generation costs for customers.

**Pipeline Growth** At Enogex, we continued to find opportunities to grow processing and gathering volumes. We closed a 15-year deal for the rights to gather and process natural gas production from nearly 500,000 net acres in northwestern Oklahoma and the Texas Panhandle. In a related transaction, we acquired approximately 235 miles of natural gas gathering assets. Those two strategic transactions have grown our gathering assets and helped increase processed volumes, which are up more than 70 percent in five years. We also announced plans to invest another \$135 million of midstream infrastructure in the region through 2013. Also in that time, we rebalanced our portfolio of natural gas contracts to reduce revenue risk in a difficult commodity market. The conversion of keep-whole contracts to fixed fee arrangements is providing a stable cash flow that's less vulnerable to the volatility of natural gas prices.

And, as this report went to press, we announced a partnership that will combine Enogex' assets with the midstream assets of Houston-based CenterPoint Energy. Once the new company is formed, the plan is to facilitate an initial public offering as a master limited partnership.

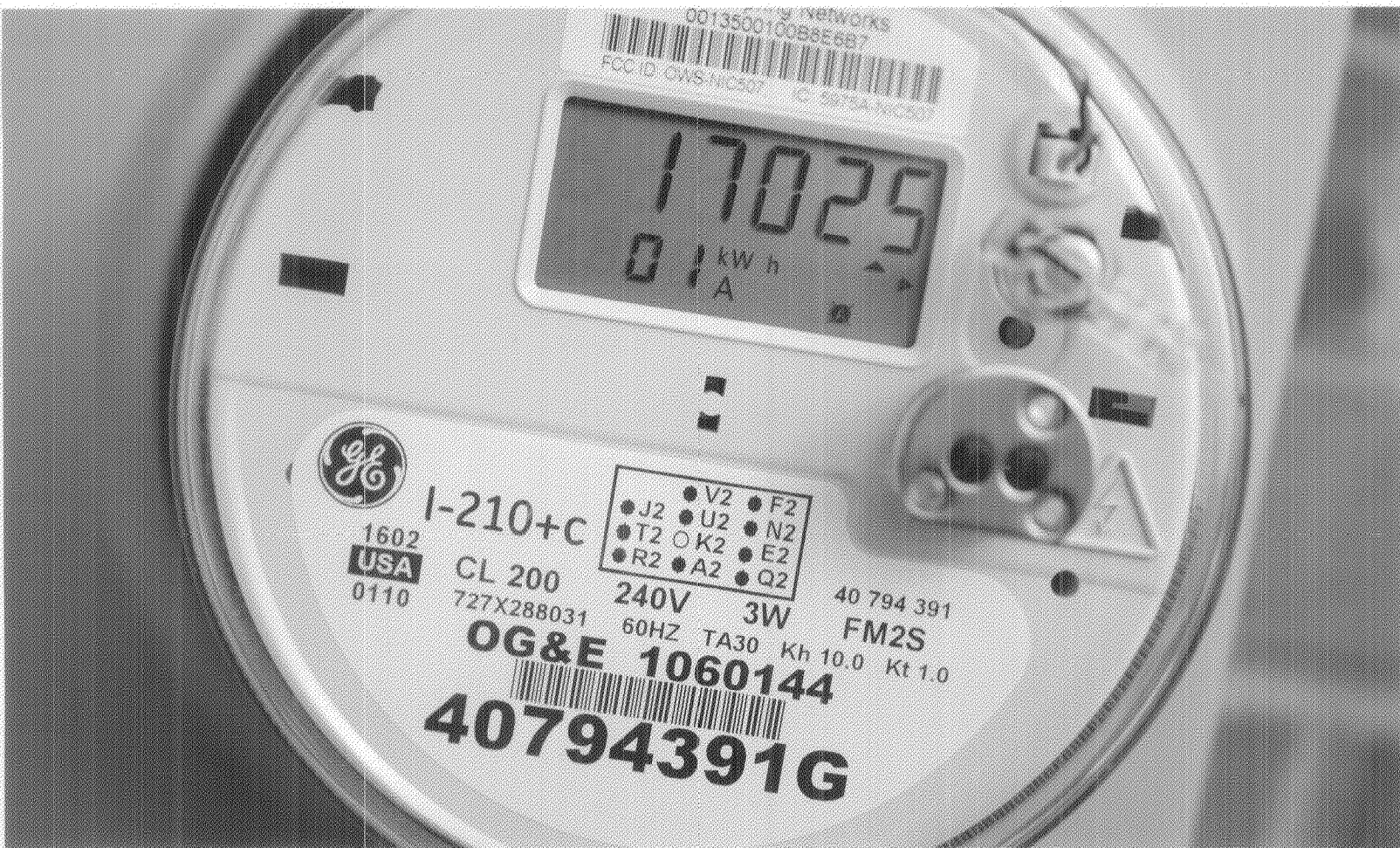
**Moving Forward** When we look to the future of the energy industry and OGE's position within it, we are proud of where we stand. That pride is embedded in our internal culture, in which cross-functional teams are seeking operational efficiencies and innovation opportunities. There is a new energy in the air as employees are actively involved in making OGE stronger and more successful in the future for all of us.



A handwritten signature in black ink that reads "Peter B. Delaney". The signature is written in a cursive style with a large initial "P".

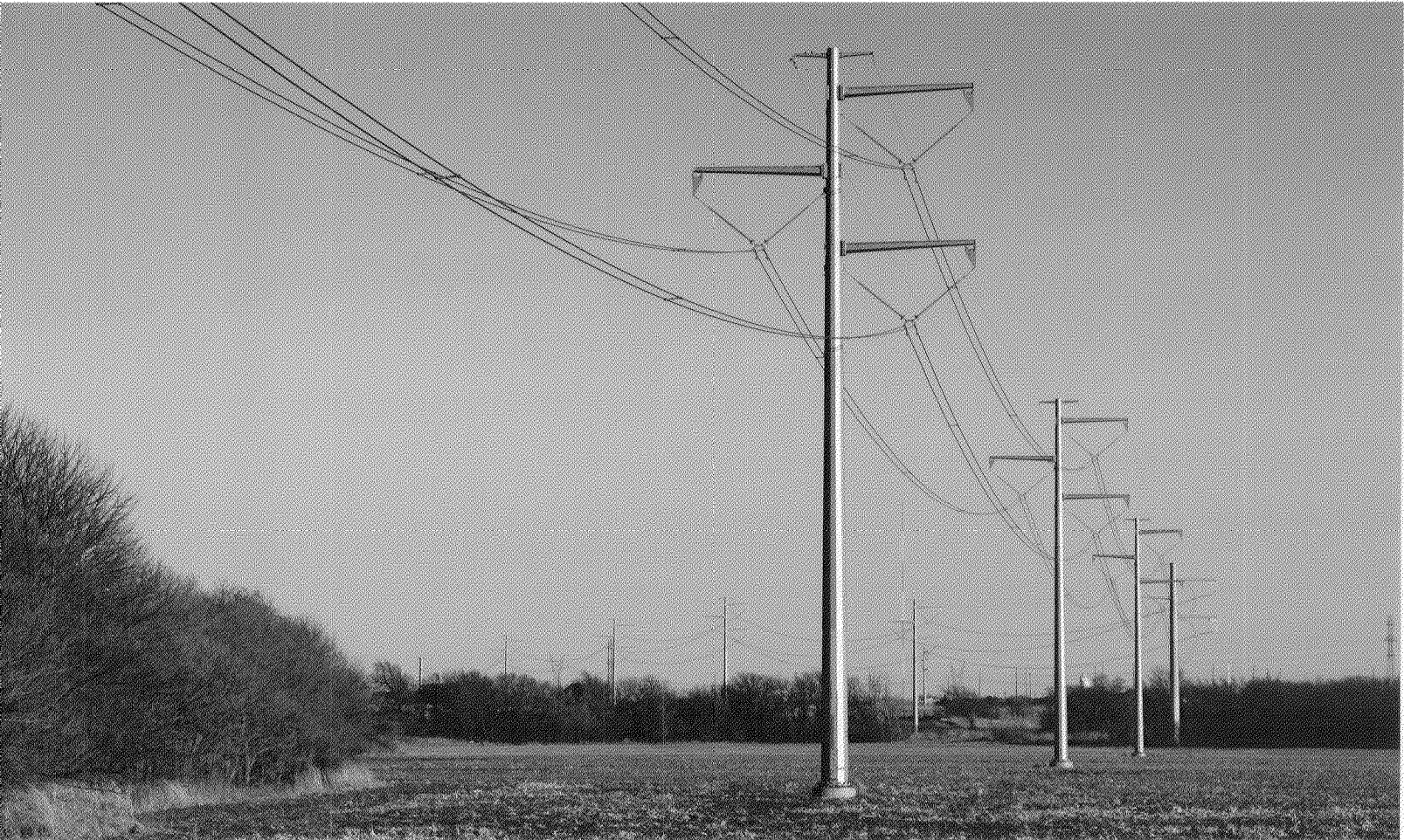
Peter B. Delaney  
Chairman, President and Chief Executive Officer

## Looking Ahead. Toward 2020.



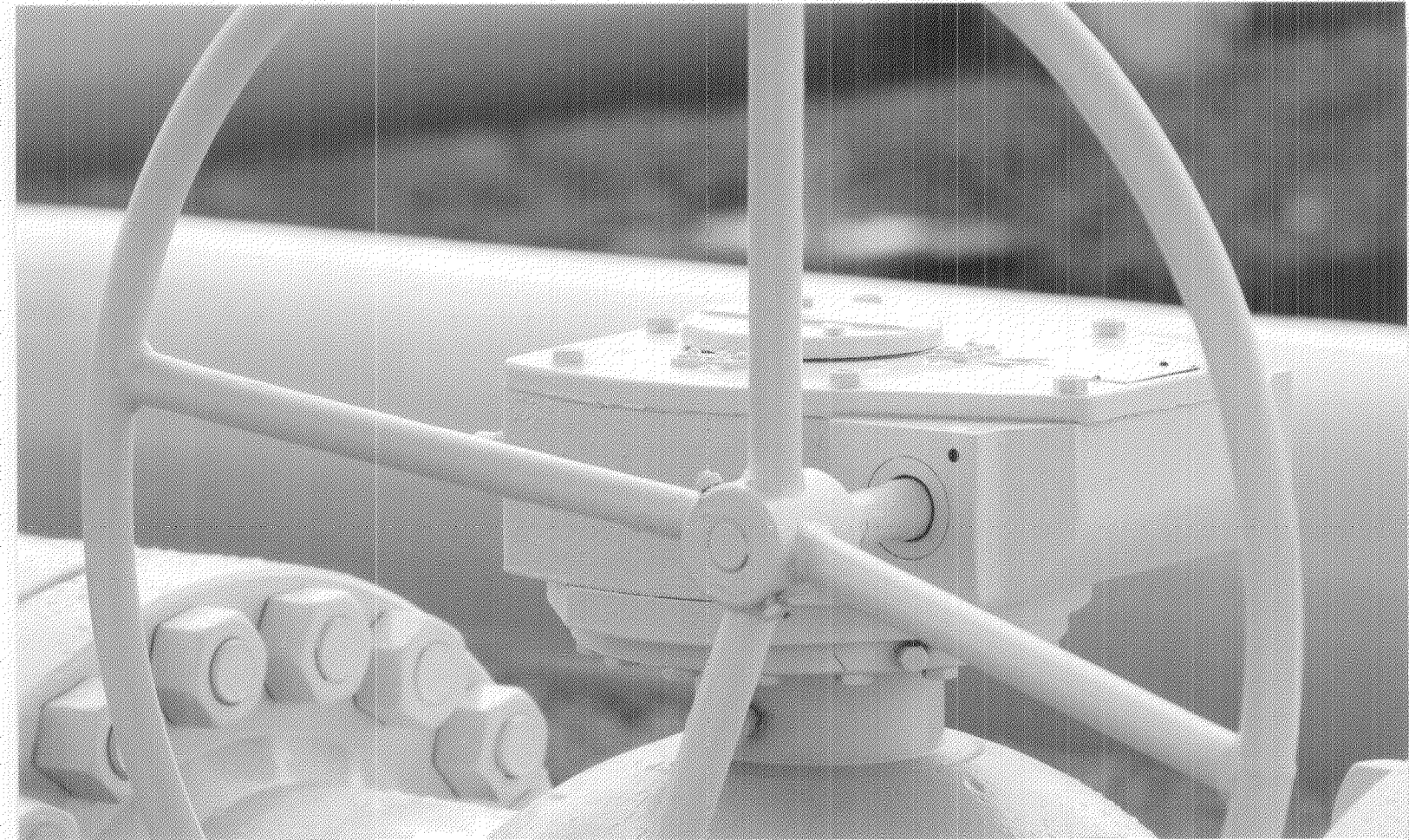
**Managing our Future** The path toward our strategic goal of not building new incremental fossil-fired generation until at least 2020 is well defined. It includes the continued implementation of demand-response programs for commercial and industrial customers, increasing enrollment in the SmartHours® residential variable peak pricing plan, and strategically executed renewable energy projects. In addition, our future calls for continued investment in our infrastructure to increase system reliability and meet load growth. Meanwhile, there is little doubt that the cost of electricity will increase in the future, primarily the result of increasing environmental regulations. We will continue evaluating our compliance, implementing responsible programs, and seeking fair and balanced solutions for our customers.

## Acting Now. Engaging Customers.



**Implementing and Innovating** We've successfully launched an online energy management tool, myOGEpower, and an innovative pricing plan, both of which have helped our customers better manage their electricity usage, and reduced demand on our system. Nearly 45,000 customers enrolled last year, and OG&E saw an estimated \$13.5 million in operational savings. Customers saved an average of \$179 on their summer bills. These programs are helping us meet the needs of our growing customer base without added generation. Meanwhile, continued investment in our infrastructure improves reliability, increases earnings and provides a return on investment for our shareholders. And while we monitor regulatory environmental actions, OG&E is already taking action, with plans to install low-NOX burners to reduce emissions at seven of our generation units. Progressive action today is helping ensure we position the company for the long term, while helping customers manage their bills.

## Looking Ahead. Opportunities To Grow.



**Strength and Growth Ahead** With more than 2.5 million acres of long-term dedications in very prolific basins, we anticipate there will be opportunities to continue investing for years to come. Active and growing drilling activity in dedicated areas translates into a robust volume forecast for 2013 and beyond. In both gathering and processing, we project strong growth for at least the next two years. Our focus remains on providing attractive returns for our shareholders through efficient operations and effective commercial management of our assets. Mindful of the volatility of natural gas prices, we anticipate that a rebound from current lows has the potential to significantly accelerate our volume growth projections. In the meantime, our confidence in our midstream business and its long-term growth prospects is strong.



## Acting Now. Increasing Volumes.



**A Year of Growth** In 2012, Enogex posted another year of record gathering and natural gas liquids (NGL) production volumes. It gained key new opportunities with the acquisition of approximately 235 miles of natural gas gathering pipelines from Chesapeake Energy's midstream companies in the greater Granite Wash area. Enogex also completed a 15-year agreement with Chesapeake for the rights to provide fee-based midstream services for production from nearly 500,000 net acres. The new Wheeler Processing Plant began operations supported by investments in new compression assets and additional gathering pipeline to serve increased natural gas volumes from producers on dedicated acreage in the northwestern Oklahoma and Texas Panhandle drilling areas. Enogex is executing on similar capital projects in the NGL-rich South Central Oklahoma Oil Province (SCOOP) to support recently secured long-term acreage dedications from producing customers.

## 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**<sup>3</sup>  
Former Chairman and  
Chief Executive Officer,  
Kerr-McGee Corporation  
(oil and gas exploration  
and production company)  
Oklahoma City

**Robert Kelley**<sup>1</sup>  
President,  
Kellco Investments Inc.  
(private investment company)  
Ardmore, Oklahoma

**Robert O. Lorenz**<sup>1,2</sup>  
Retired Managing Partner,  
Arthur Andersen  
(accounting firm)  
Oklahoma City

**Leroy C. Richie**<sup>2,3</sup>  
Counsel,  
Lewis & Munday, P.C.  
(law firm)  
Detroit, Michigan

**James H. Brandi**<sup>2,3</sup>  
Retired Managing Director,  
BNP Paribas Securities Corp.  
(investment banking company)  
New York City, New York

**Wayne H. Brunetti**<sup>1,3</sup>  
Retired Chairman,  
Xcel Energy Inc.  
(electric utility)  
Denver, Colorado

**John D. Groendyke**<sup>2,3</sup>  
Chairman and  
Chief Executive Officer,  
Groendyke Transport, Inc.  
(bulk transportation company)  
Enid, Oklahoma

**Kirk Humphreys**<sup>1,3</sup>  
Chairman,  
The Humphreys Company, LLC  
(real estate development company)  
and Chairman,  
Carlton Landing, LLC  
(real estate development company)  
Oklahoma City

**Judy R. McReynolds**<sup>2,3</sup>  
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  
and 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. McQuiston**  
Vice President,  
Strategic Planning,  
Performance Improvement  
and Chief Information Officer  
OGE Energy Corp., OG&E

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

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

**Paul L. Renfrow**  
Vice President, Public Affairs,  
Human Resources  
and Health & Safety  
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

<sup>1</sup> Member of the audit committee

<sup>2</sup> Member of the nominating and  
corporate governance committee

<sup>3</sup> Member of the compensation committee

Red number indicates committee chairman

OGE Energy Corp. Annual Report  
2012 Financial Section

(As included in the Company's Form 10-K filed  
with the SEC on February 27, 2013)

## MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

### 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 as well as inflation rates and monetary fluctuations;
- 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;
- The cost of protecting assets against, or damage due to, terrorism or cyber attacks and other catastrophic events;
- 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 three business segments: (i) electric utility, (ii) natural gas transportation and storage and (iii) natural gas gathering and processing.

The electric utility segment generates, transmits, distributes and sells electric energy in Oklahoma and western Arkansas. Its operations are conducted through Oklahoma Gas and Electric Company ("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 and storing 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. During the third quarter of 2012, the operations and activities of Enogex Energy Resources LLC, wholly-owned subsidiary of Enogex LLC (collectively with its subsidiaries, "Enogex LLC") ("EER") were fully integrated with those of Enogex through the creation of a new commodity management organization. This new organization is intended to facilitate the execution of Enogex's strategy through an enhanced focus on asset optimization and active management of its growing natural gas, NGLs and condensate positions. The operations of EER, including asset management activities, have been included in the natural gas transportation and storage segment and have been restated for all prior periods presented. Enogex's operations are now organized into two business segments: (i) natural gas transportation and storage and (ii) natural gas gathering and processing. At December 31, 2012, OGE Energy indirectly owns a 78.9 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.

## 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 focusing on safety, efficiency, reliability, customer service and risk management.

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.

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 expects to maintain a diverse generation portfolio while remaining environmentally responsible. 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 as well as allow customers to monitor and manage their energy usage, which should help reduce demand during critical peak times, resulting in lower capacity requirements. 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. The Smart Grid program also provides benefits to OG&E, including more efficient use of its resources and access to increased information about customer usage, which should enable OG&E to have better distribution system planning data, better response to customer usage questions and faster detection and restoration of system outages. 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").

Enogex's business plan entails growing its businesses and providing attractive financial returns through efficient operations and effective commercial management of its assets. Enogex also plans to capture growth opportunities through expansion projects, increased utilization of existing assets and through acquisitions (including joint ventures) in and around its footprint and attracting new customers. 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.

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. 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

#### 2012 Compared to 2011

Net income attributable to OGE Energy was \$355.0 million, or \$3.58 per diluted share, in 2012 as compared to \$342.9 million, or \$3.45 per diluted share, in 2011. The increase in net income attributable to OGE Energy of \$12.1 million, or 3.5 percent, or \$0.13 per diluted share, in 2012 as compared to 2011 was primarily due to:

- An increase in net income at OG&E of \$17.0 million, or 6.5 percent, or \$0.18 per diluted share of the Company's common stock, primarily due to a higher gross margin and lower income tax expense. The higher gross margin was primarily due to increased recovery of investments and increased transmission revenue partially offset by milder weather in OG&E's service territory. These increases were partially offset by higher other operation and maintenance expense, higher depreciation and amortization expense, lower allowance for equity funds used during construction and higher interest expense;
- A decrease in net income at Enogex of \$8.1 million, or 9.9 percent, or \$0.08 per diluted share of the Company's common stock, primarily due to higher other operation and maintenance expense, higher depreciation and amortization expense, lower other income 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 2011, higher interest expense and OGE Energy's lower membership interest in Enogex Holdings. These decreases were partially offset by a higher gross margin related to (i) increased gathering rates and volumes associated with ongoing expansion projects and increased volumes from gas gathering assets acquired in November 2011 and August 2012 and (ii) increased inlet volumes partially offset by lower average natural gas and NGLs prices. Also having a positive impact on net income was a higher gain on insurance proceeds in 2012 and an impairment related to the Atoka Midstream LLC joint venture ("Atoka") processing plant in 2011; and

- An increase in net income at OGE Energy of \$3.2 million, or \$0.03 per diluted share of the Company's common stock, primarily due to higher other income due to a decrease in deferred compensation losses partially offset by higher interest expense and a lower income tax benefit in 2012.

#### Non-Recurring Items

During 2012, Enogex had an increase in net income of \$4.6 million due to a gain on insurance proceeds related to the reimbursement of costs incurred to replace the damaged train at the Cox City natural gas processing plant partially offset by a decrease in net income of \$2.1 million related to sales taxes on the assets acquired in the gas gathering acquisitions in August 2012, as discussed in Note 3 of Notes to Consolidated Financial Statements, which Enogex does not consider to be reflective of its ongoing performance. During 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.

#### 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 OGE Energy's lower membership interest in Enogex Holdings partially offset by a higher gross margin primarily from higher NGLs prices and increased gathered volumes associated with ongoing expansion projects, 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 the 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.

#### Non-Recurring Item

During 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 Enogex's natural gas storage inventory at the lower of cost or market value. The offsetting gains from the sale of withdrawals from inventory were realized during the first quarter of 2012.

#### Recent Developments and Regulatory Matters

##### OG&E SPP Transmission Projects

In 2007, the SPP notified OG&E to construct 44 miles of a new 345 kilovolt transmission line originating at OG&E's existing Sooner 345 kilovolt substation and proceeding 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 connects to the companion line constructed in Kansas by Westar Energy. The transmission line was placed in service in April 2012. The total capital expenditures associated with this project were \$45 million.

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 extends 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 transmission line was completed in April 2012. The total capital expenditures associated with this project were \$157 million.

As discussed in Note 17 of Notes to Consolidated Financial Statements, the OCC approved a settlement agreement in OG&E's 2011 Oklahoma rate case filing that included an expedited procedure for recovering the costs of the two projects. On July 31, 2012, OG&E filed an application with the OCC requesting an order authorizing recovery for the two projects through the SPP transmission systems additions rider. On October 2, 2012, all parties signed a settlement agreement in this matter which stated: (i) the parties agree not to oppose requested relief sought by OG&E, (ii) OG&E will host meetings to discuss the SPP's transmission planning process, including any future transmission projects for which OG&E has received a notice to construct from the SPP,

and (iii) there will be opportunities for parties to provide input related to transmission planning studies that the SPP performs to identify future transmission projects. On October 25, 2012, the OCC issued an order approving the settlement agreement and granting OG&E cost recovery for the two projects. OG&E initiated cost recovery beginning with the first billing cycle in November 2012.

#### **OG&E Demand and Energy Efficiency Program Filing**

On July 2, 2012, OG&E filed an application with the OCC requesting approval of OG&E's 2013 demand portfolio, the authorization to recover the program costs, lost revenues associated with any achieved energy, demand savings and performance based incentives through the demand program rider and the recovery of costs associated with research and development investments. On July 16, 2012, OG&E filed an amended application which modified various calculations to reflect the rate of return authorized by the OCC in OG&E's 2011 rate case order and provided for consideration of a peak time rebate program. On December 20, 2012, the OCC approved a settlement with all parties in this matter. Key terms of the settlement included (i) approval of the program budgets proposed by OG&E and an additional amount of approximately \$7 million over the three-year period for the energy efficiency programs, (ii) approval of OG&E's proposed Demand Program Rider tariff, (iii) the recovery through the Demand Program Rider of the increased program costs and the net lost revenues, incentives and research and development investments requested by OG&E, with the exception of lost revenues resulting from the Integrated Volt Var Control program (automated intelligence to control voltage and power on the distribution lines) and incentives for the SmartHours® and Integrated Volt Var Control demand response programs, (iv) recovery of the program costs on a levelized basis over the three-year period, (v) consideration of implementing a peak time rebate program in 2015 and (vi) the periodic filing of additional reports. The Demand Program Rider became effective on January 1, 2013.

#### **OG&E Fuel Adjustment Clause Review for Calendar Year 2010**

The OCC routinely reviews the costs recovered from customers through OG&E's fuel adjustment clause. On August 19, 2011, the OCC Staff filed an application to review OG&E's fuel adjustment clause for calendar year 2010, including the prudence of OG&E's electric generation, purchased power and fuel procurement costs. OG&E responded by filing direct testimony and the minimum filing review package on October 18, 2011. On September 26, 2012, the administrative law judge recommended that the OCC find that for the calendar year 2010 OG&E's generation, purchase power and fuel procurement processes and costs, including the cost of replacement power for the Sooner 2 outage, were prudent and no disallowance (as discussed below) for any of these expenses is warranted. On January 31, 2013, the OCC issued an order approving the administrative law judge's recommendation. Previously, the Oklahoma Industrial Energy Consumers recommended that the OCC disallow recovery of approximately \$44 million of costs previously recovered through OG&E's fuel adjustment clause. These recommendations were based on allegations that OG&E's lower cost coal-fired generation was

underutilized, that OG&E failed to aggressively pursue purchasing power at a cost lower than its marginal cost of generation and that OG&E should be found imprudent related to an unplanned outage at OG&E's Sooner 2 coal unit in November and December 2010. Previously, the OCC Staff recommended approval of OG&E's actions related to utilization of coal plants and practices related to purchasing power but recommended that OG&E refund \$3 million to customers because of the Sooner 2 outage.

#### **Texas Panhandle Gathering Divestiture**

On January 2, 2013, Enogex and one of its five largest customers entered into new agreements, effective January 1, 2013, relating to the customer's gathering and processing volumes on the Texas portion of Enogex's system. The effects of this new arrangement are (i) a fixed fee processing agreement replaces the previous keep-whole agreement, (ii) the acreage dedicated by the customer to Enogex for gathering and processing in Texas has been increased for an extended term and (iii) the sale by Enogex of certain gas gathering assets in the Texas Panhandle portion of Enogex's system to this customer for cash proceeds of approximately \$35 million. The sale of these assets was approved by the Company's and Enogex's Board of Directors in November 2012, therefore these assets were classified as held for sale on the Company's Consolidated Balance Sheet at December 31, 2012. Enogex expects to recognize a pre-tax gain of approximately \$10 million in the first quarter of 2013 in its natural gas gathering and processing segment from the sale of these assets.

#### **Enogex Western Oklahoma/Texas Panhandle Natural Gas Gathering and Processing System Expansions**

In August 2012, Enogex completed construction of its cryogenic processing plant in Wheeler County, Texas, which added 200 million cubic feet per day ("MMcf/d") of rich gas processing capacity to Enogex's system, and is supported by the installation of 9,400 horsepower of field compression, as well as 6,000 horsepower of inlet compression to facilitate additional flexibility in the operation of Enogex's "super-header" gathering system. The remainder of the inlet compression facilities is expected to be in service during the second quarter of 2013.

In support of significant long-term acreage dedications from its customers in the area, Enogex has expanded its gathering infrastructure in western Oklahoma and the Texas Panhandle. These expansions included the installation of 39,700 horsepower of low pressure compression and 235 miles of gathering pipe across the area, which was completed during the third quarter of 2012.

In support of significant long-term acreage dedications from its customers in the area, Enogex is expanding its gathering infrastructure in southern Oklahoma. The initial phase of these expansions include the installation of approximately 20,000 horsepower of compression and approximately 100 miles of gathering pipeline, which are expected to be in service by the end of the first quarter of 2013. The remainder of the expansion includes the installation of approximately 50,000 horsepower of compression and approximately 300 miles of gathering pipeline, which are expected to be in service by the end of 2013.

Enogex is constructing a cryogenic processing plant in Custer County, Oklahoma, which is expected add 200 MMcf/d of natural gas processing capacity to Enogex's system, and is expected to be supported by the installation of 6,000 horsepower of inlet compression and four miles of transmission pipeline. This plant will be connected to the Enogex "super-header" gathering system and is expected to be in service by the end of 2013.

The capital expenditures related to the above 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."

### Gas Gathering Acquisitions

On August 1, 2012, Enogex entered into agreements with Chesapeake Midstream Gas Services, L.L.C. and Mid-America Midstream Gas Services, L.L.C., wholly-owned subsidiaries of Access Midstream Partners, L.P. and Chesapeake Midstream Development, L.P., respectively, pursuant to which Enogex agreed to acquire approximately 235 miles of natural gas gathering pipelines, right-of-ways and certain other midstream assets that provide natural gas gathering services in the greater Granite Wash area. The transactions closed on August 31, 2012. The aggregate purchase price for these transactions was approximately \$78.6 million including reimbursement for certain permitted capital expenditures incurred during the period beginning June 1, 2012 and ending August 31, 2012. Enogex utilized cash generated from operations and bank borrowings to fund the purchase. In addition, Enogex also incurred acquisition-related costs of \$3.5 million for sales taxes on acquired assets, which are included in taxes other than income. Enogex expects the purchase price allocations to be completed by the end of the first quarter of 2013. The Company believes that the acquisition transactions will provide Enogex with key new opportunities in the greater Granite Wash area.

In connection with these agreements, Enogex entered into a gas gathering and processing agreement with Chesapeake Energy Marketing, Inc. and Chesapeake Exploration L.L.C. ("Chesapeake") effective September 1, 2012 pursuant to which Enogex began providing fee-based natural gas gathering, compression, processing and transportation services to Chesapeake with respect to certain acreage dedicated by Chesapeake.

The capital expenditures related to the above agreements 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."

### 2013 Outlook

The Company's 2013 earnings guidance is between approximately \$335 million and \$360 million of net income, or \$3.35 to \$3.60 per average diluted share.

### Key Assumptions for 2013 Include:

#### Consolidated OGE

- Approximately 100 million average diluted shares outstanding;
- An effective tax rate of approximately 30 percent; and
- A projected loss at the holding company between approximately \$2 million and \$4 million, or \$0.02 to \$0.04 per diluted share, primarily due to interest expense relating to long and short-term debt borrowings partially offset by tax deductions.

#### OG&E

The Company projects OG&E to earn approximately \$280 million to \$290 million or \$2.80 to \$2.90 per average diluted share in 2013 and is based on the following assumptions:

- Normal weather patterns are experienced for the remainder of the year;
- Gross margin on revenues of approximately \$1.290 billion to \$1.295 billion based on sales growth of approximately 1.5 percent on a weather-adjusted basis;
- Approximately \$75 million of gross margin is primarily attributed to regionally allocated transmission projects;
- Operating expenses of approximately \$770 million to \$780 million, with operation and maintenance expenses comprising 57 percent of the total;
- Interest expense of approximately \$130 million to \$135 million which assumes a \$3 million allowance for borrowed funds used during construction reduction to interest expense and \$250 million of long-term debt issued in the first half of 2013;
- Allowance for equity funds used during construction of approximately \$10 million; and
- An effective tax rate of approximately 28 percent.

OG&E has significant seasonality in its earnings. OG&E typically shows minimal earnings in the first and fourth quarters with a majority of earnings in the third quarter due to the seasonal nature of air conditioning demand.

#### Enogex

The Company projects Enogex to earn approximately \$55 million to \$75 million, or \$0.55 to \$0.75 per average diluted share and Enogex Holdings earnings before interest, taxes, depreciation and amortization ("EBITDA") between \$213 million and \$241 million, in 2013 net of non-controlling interest, and is based on the following assumptions:

- Total Enogex anticipated gross margin of between approximately \$470 million and \$500 million. The gross margin assumption includes:
  - Natural gas transportation and storage gross margin contribution of between approximately \$130 million and \$140 million, of which 83 percent is attributable to the transportation business;
  - Natural gas gathering and processing gross margin contribution of between approximately \$340 million and \$360 million, of which 51 percent is attributable to the processing business;
  - Key factors affecting the natural gas gathering and processing gross margin forecast are:



- Assumed increase of approximately 10 to 15 percent in gathered volumes over 2012;
- Assumed increase of approximately 10 to 15 percent in processable\* volumes over 2012;
- At the midpoint of Enogex's natural gas gathering and processing assumption Enogex has assumed:
  - An average processing contract mix of 48 percent fixed-fee, 23 percent percent-of-liquids, 19 percent percent-of-proceeds and 10 percent keep-whole;
  - Average natural gas price of \$3.38 per million British thermal unit ("MMBtu") in 2013;
  - Average NGLs price of \$0.82 per gallon in 2013;
  - Average price per gallon of condensate of \$2.13 in 2013;
  - Ethane is projected to be in rejection for 2013;
  - Approximately 50 percent of NGLs volumes are expected to flow to Mt. Belvieu; and
  - A 10 percent change in the average NGLs price for the entire year impacts net income approximately \$5 million;
- Enogex has assumed operating expenses of approximately \$325 million to \$335 million, with operation and maintenance expenses comprising 54 percent of the total;
- A pre-tax gain of approximately \$10 million associated with asset sales in the first quarter of 2013;
- Interest expense of approximately \$30 million to \$35 million;
- An effective tax rate of approximately 38 percent; and
- Bronco Midstream Holdings, LLC, Bronco Midstream Holdings II, LLC, (collectively the "ArcLight group") will own approximately 22 percent of Enogex Holdings by the end of 2013.

#### 2014 Volume Projections for Enogex:

- Assumed increase of approximately five to 10 percent in gathered volumes over 2013; and
- Assumed increase of approximately 10 to 20 percent in processable\* volumes over 2013.

\* Processable volumes are the natural gas production that are on Enogex's gathering systems that are available to be processed, some of which is moved off of the system and is not processed under one of Enogex's processing agreements. Processable volumes include condensate volumes which are captured in the gathering pipeline and therefore not included in plant inlet volumes.

EBITDA is a supplemental non-GAAP financial measure used by external users of the Company's financial statements such as investors, commercial banks and others; therefore, the Company has included the table below which provides a reconciliation of projected EBITDA to projected net income attributable to Enogex Holdings at the midpoint of Enogex Holdings' earnings assumptions for 2013, which does not include the effect of income taxes whereas OGE Energy's portion of Enogex Holdings' net income included in OGE Energy's earnings guidance does reflect the effect of income taxes. Enogex Holding's net income shown in the EBITDA table does not include the effect of income taxes because Enogex Holdings is a partnership and is not subject to income taxes. Each partner is responsible for paying their own income taxes. For a discussion of the reasons for the use of EBITDA, as well as its limitations as an analytical tool, see "Non-GAAP Financial Measure" below.

(In millions, year ended December 31)

2013<sup>(A),(B)</sup>

#### Reconciliation of projected EBITDA to projected net income attributable to Enogex Holdings

Net income attributable to Enogex Holdings	\$132
Add:	
Interest expense, net	33
Depreciation and amortization expense <sup>(C)</sup>	123
<b>EBITDA</b>	<b>\$288</b>
<b>OGE Energy's portion</b>	<b>\$228</b>

<sup>(A)</sup> Based on the midpoint of Enogex Holdings' earnings guidance for 2013.

<sup>(B)</sup> As of November 1, 2010, Enogex Holdings' earnings are no longer subject to tax (other than Texas state margin taxes) and are taxable at the individual partner level.

<sup>(C)</sup> Includes amortization of certain customer-based intangible assets associated with the acquisition from Cordillera Energy Partners III, LLC ("Cordillera") in November 2011, which is included in gross margin for financial reporting purposes.

#### 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, 2012, 2011 and 2010 and the Company's consolidated financial position at December 31, 2012 and 2011. 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)

	2012	2011	2010
Operating income	\$ 676.9	\$ 646.7	\$ 593.9
Net income attributable to OGE Energy	\$ 355.0	\$ 342.9	\$ 295.3
Basic average common shares outstanding	98.6	97.9	97.3
Diluted average common shares outstanding	99.1	99.2	98.9
Basic earnings per average common share attributable to OGE Energy common shareholders	\$ 3.60	\$ 3.50	\$ 3.03
Diluted earnings per average common share attributable to OGE Energy common shareholders	\$ 3.58	\$ 3.45	\$ 2.99
Dividends declared per common share	\$1.5950	\$1.5175	\$1.4625

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)

	2012	2011	2010
<b>Operating income (loss) by business segment</b>			
OG&E (Electric Utility)	\$489.4	\$472.3	\$413.7
Enogex (Natural Gas Midstream Operations)			
Natural gas transportation and storage <sup>(A)</sup>	45.1	56.4	60.4
Natural gas gathering and processing	140.5	118.7	123.9
Other operations <sup>(B)</sup>	1.9	(0.7)	(4.1)
<b>Consolidated operating income</b>	<b>\$676.9</b>	<b>\$646.7</b>	<b>\$593.9</b>

<sup>(A)</sup> During the third quarter of 2012, the operations and activities of EER were fully integrated with those of Enogex through the creation of a new commodity management organization.

The operations of EER, including asset management activities, have been included in the natural gas transportation and storage segment and have been restated for all prior periods presented.

<sup>(B)</sup> 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)	2012	2011	2010
<b>OG&amp;E (Electric Utility)</b>			
Operating revenues	\$2,141.2	\$2,211.5	\$2,109.9
Cost of goods sold	879.1	1,013.5	1,000.2
Gross margin on revenues	1,262.1	1,198.0	1,109.7
Other operation and maintenance	446.3	436.0	418.1
Depreciation and amortization	248.7	216.1	208.7
Taxes other than income	77.7	73.6	69.2
Operating income	489.4	472.3	413.7
Interest income	0.2	0.5	0.1
Allowance for equity funds used			
during construction	6.2	20.4	11.4
Other income	8.0	8.0	6.5
Other expense	4.3	8.4	1.6
Interest expense	124.6	111.6	103.4
Income tax expense	94.6	117.9	111.0
Net income	\$ 280.3	\$ 263.3	\$ 215.7
Operating revenues by classification			
Residential	\$ 878.0	\$ 943.5	\$ 894.8
Commercial	523.5	531.3	521.0
Industrial	206.8	216.0	212.5
Oilfield	163.4	165.1	162.8
Public authorities and street light	202.4	207.4	200.8
Sales for resale	54.9	65.3	65.8
System sales revenues <sup>(A)</sup>	2,029.0	2,128.6	2,057.7
Off-system sales revenues <sup>(B)</sup>	36.5	36.2	21.7
Other	75.7	46.7	30.5
Total operating revenues	\$2,141.2	\$2,211.5	\$2,109.9
Megawatt-hour ("MWH") sales			
by classification (in millions)			
Residential	9.1	9.9	9.6
Commercial	7.0	6.9	6.7
Industrial	4.0	3.9	3.8
Oilfield	3.3	3.2	3.1
Public authorities and street light	3.3	3.2	3.0
Sales for resale	1.3	1.4	1.4
System sales	28.0	28.5	27.6
Off-system sales	1.4	1.0	0.5
Total sales	29.4	29.5	28.1
Number of customers	798,110	789,146	782,558
Weighted-average cost of energy			
per kilowatt-hour (cents)			
Natural gas	2.930	4.328	4.638
Coal	2.310	2.064	1.911
Total fuel	2.437	2.897	3.012
Total fuel and purchased power	2.806	3.215	3.309
Degree days <sup>(C)</sup>			
Heating – Actual	2,667	3,359	3,528
Heating – Normal	3,349	3,631	3,631
Cooling – Actual	2,561	2,776	2,328
Cooling – Normal	2,092	1,911	1,911

<sup>(A)</sup> Sales to OG&E's customers.

<sup>(B)</sup> Sales to other utilities and power marketers.

<sup>(C)</sup> 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.

## 2012 Compared to 2011

OG&E's operating income increased \$17.1 million, or 3.6 percent, in 2012 as compared to 2011 primarily due to a higher gross margin partially offset by higher other operation and maintenance expense and higher depreciation and amortization expense.

### Gross Margin

Operating revenues were \$2,141.2 million in 2012 as compared to \$2,211.5 million in 2011, a decrease of \$70.3 million, or 3.2 percent. Cost of goods sold was \$879.1 million in 2012 as compared to \$1,013.5 million in 2011, a decrease of \$134.4 million, or 13.3 percent. Gross margin was \$1,262.1 million in 2012 as compared to \$1,198.0 million in 2011, an increase of \$64.1 million, or 5.4 percent. The below factors contributed to the change in gross margin:

(In millions)	\$ Change
Price variance <sup>(A)</sup>	\$ 54.1
Wholesale transmission revenue <sup>(B)</sup>	28.5
New customer growth	11.5
Non-residential demand and related revenues	4.9
Enogex transportation credit <sup>(C)</sup>	3.3
Arkansas rate increase	2.8
Oklahoma rate increase	2.7
Renewal of wholesale contract with customer	1.3
Other	0.3
Quantity variance (primarily weather)	(45.3)
<b>Change in gross margin</b>	<b>\$ 64.1</b>

<sup>(A)</sup> Increased due to revenues from the recovery of investments, including the Crossroads wind farm and smart grid.

<sup>(B)</sup> Increased 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.

<sup>(C)</sup> Increased due to a credit to OG&E's customers in 2011 related to the settlement of OG&E's 2009 fuel adjustment clause review.

Cost of goods sold for OG&E consists of fuel used in electric generation, purchased power and transmission related charges. Fuel expense was \$642.4 million in 2012 as compared to \$775.0 million in 2011, a decrease of \$132.6 million, or 17.1 percent, primarily due to lower natural gas prices. 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 2012, OG&E's fuel mix was 52 percent coal, 42 percent natural gas and six percent wind. In 2011, OG&E's fuel mix was 58 percent coal, 39 percent natural gas and three percent wind. Purchased power costs were \$223.0 million in 2012 as compared to \$230.7 million in 2011, a decrease of \$7.7 million, or 3.3 percent, primarily due to a decrease in cogeneration purchases and purchases in the energy imbalance service market due to milder weather partially offset by an increase in short-term power purchases. Transmission related charges were \$13.7 million in 2012 as compared to \$7.8 million in 2011, an increase of \$5.9 million, or 75.6 percent, primarily due to higher SPP charges for the base plan projects of other utilities.

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 \$446.3 million in 2012 as compared to \$436.0 million in 2011, an increase of \$10.3 million, or 2.4 percent. The below factors contributed to the change in other operations and maintenance expense:

(In millions)	\$ Change
Salaries and wages <sup>(A)</sup>	\$ 6.4
Contract professional and technical services (related to smart grid) <sup>(B)</sup>	4.2
Employee benefits <sup>(C)</sup>	3.4
Administration and assessment fees (primarily SPP and North American Electric Reliability Corporation)	3.4
Wind farm lease expense (primarily Crossroads) <sup>(B)</sup>	3.0
Injuries and damages	1.9
Ongoing maintenance at power plants <sup>(B)</sup>	1.9
Software (primarily smart grid) <sup>(B)</sup>	1.8
Other	0.2
Temporary labor	(1.7)
Uncollectibles	(2.4)
Vegetation management (primarily system hardening) <sup>(B)</sup>	(3.0)
Allocations from holding company (primarily lower contract professional services and lower payroll and benefits)	(3.1)
Capitalized labor	(5.7)
<b>Change in other operation and maintenance expense</b>	<b>\$10.3</b>

<sup>(A)</sup> Increased primarily due to salary increases and an increase in incentive compensation expense partially offset by lower headcount in 2012 and a decrease in overtime expense.

<sup>(B)</sup> Includes costs that are being recovered through a rider.

<sup>(C)</sup> Increased primarily due to an increase in worker's compensation accruals, an increase in medical expense and an increase in postretirement medical expense partially offset by a decrease in pension expense.

Depreciation and amortization expense was \$248.7 million in 2012 as compared to \$216.1 million in 2011, an increase of \$32.6 million, or 15.1 percent, primarily due to additional assets being placed in service throughout 2011 and 2012, including the Crossroads wind farm, which was fully in service in January 2012, the Sooner-Rose Hill and Sunnyside-Hugo transmission projects, which were fully in service in April 2012, and the smart grid project which was completed in late 2012.

#### Additional Information

**Allowance for Equity Funds Used During Construction.** Allowance for equity funds used during construction was \$6.2 million in 2012 as compared to \$20.4 million in 2011, a decrease of \$14.2 million, or 69.6 percent, primarily due to higher levels of construction costs for the Crossroads wind farm in 2011.

**Other Income.** Other income was \$8.0 million in both 2012 and 2011. Factors affecting other income included an increased margin of \$8.8 million recognized in the guaranteed flat bill program in 2012 as a result of milder weather offset by a decrease of \$8.9 million related to the benefit associated with the tax gross-up of allowance for equity funds used during construction.

**Other Expense.** Other expense was \$4.3 million in 2012 as compared to \$8.4 million in 2011, a decrease of \$4.1 million, or 48.8 percent primarily due to a decrease in charitable contributions.

**Interest Expense.** Interest expense was \$124.6 million in 2012 as compared to \$111.6 million in 2011, an increase of \$13.0 million, or 11.6 percent, primarily due to a \$6.9 million increase in interest expense related to lower allowance for borrowed funds used during construction costs for the Crossroads wind farm in 2011 and a \$5.5 million increase in interest expense related to the issuance of long-term debt in May 2011.

**Income Tax Expense.** Income tax expense was \$94.6 million in 2012 as compared to \$117.9 million in 2011, a decrease of \$23.3 million, or 19.8 percent. The decrease in income tax expense was primarily due to an increase in the amount of Federal renewable energy tax credits recognized associated with the Crossroads wind farm and lower pre-tax income in 2012 as compared to 2011.

#### 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

Operating revenues were \$2,211.5 million in 2011 as compared to \$2,109.9 million in 2010, an increase of \$101.6 million, or 4.8 percent. Cost of goods sold was \$1,013.5 million in 2011 as compared to \$1,000.2 million in 2010, an increase of \$13.3 million, or 1.3 percent. 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 below factors contributed to the change in gross margin:

(In millions)	\$ Change
Quantity variance (primarily weather)	\$27.4
Price variance <sup>(A)</sup>	23.9
Transmission revenue <sup>(B)</sup>	15.3
New customer growth	13.1
Arkansas rate increase	6.0
Non-residential demand and related revenues	5.0
Renewal of wholesale contract with customer	3.1
Other	0.2
Enogex transportation credit <sup>(C)</sup>	(5.7)
<b>Change in gross margin</b>	<b>\$88.3</b>

<sup>(A)</sup> Increased due to revenues from the recovery of investments, including the Windspeed transmission line, Oklahoma demand program, smart grid, system hardening, storm recovery, the Crossroads wind farm and the OU Spirit wind farm, and higher revenues from industrial and oilfield customers.

<sup>(B)</sup> Increased 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.

<sup>(C)</sup> Decreased due to a credit to OG&E's customers in 2011 related to the settlement of OG&E's 2009 fuel adjustment clause review.

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.

#### 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 below factors contributed to the change in other operations and maintenance expense:

(In millions)	\$ Change
Allocations from holding company <sup>(A)</sup>	\$15.5
Salaries and wages <sup>(B)</sup>	12.1
Other marketing and sales expense (primarily demand-side management initiatives) <sup>(C)</sup>	4.6
Uncollectible expense	3.1
Fleet transportation expense (primarily higher fuel costs in 2011)	1.6
Temporary labor expense	1.3
Administration and assessment fees (primarily SPP)	1.2
Vegetation management (primarily system hardening) <sup>(C)</sup>	(2.9)
Other	(3.8)
Injuries and damages (primarily higher reserves on claims in 2010)	(5.0)
Employee benefits <sup>(D)</sup>	(9.8)
<b>Change in other operation and maintenance expense</b>	<b>\$17.9</b>

<sup>(A)</sup> Increased primarily related to payroll and benefits expense, contract technical and construction services and contract professional services

<sup>(B)</sup> Increased primarily due to salary increases in 2011, increased incentive compensation expense and increased overtime expense primarily due to storms in April and August 2011.

<sup>(C)</sup> Includes costs that are being recovered through a rider

<sup>(D)</sup> Decreased 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 workers compensation accruals in 2011.

#### 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 the Crossroads wind farm in 2011.

**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 the Crossroads wind farm; 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.

Enogex (Natural Gas Midstream Operations)

(In millions, year ended December 31)	Natural Gas Transportation and Storage	Natural Gas Gathering and Processing	Eliminations	Total
<b>2012</b>				
Operating revenues	\$639.5	\$1,222.6	\$(253.5)	\$1,608.6
Cost of goods sold	504.9	868.7	(253.5)	1,120.1
Gross margin on revenues	134.6	353.9	-	488.5
Other operation and maintenance	49.8	123.1	-	172.9
Depreciation and amortization	24.0	84.8	-	108.8
Impairment of assets	-	0.4	-	0.4
Gain on insurance proceeds	-	(7.5)	-	(7.5)
Taxes other than income	15.7	12.6	-	28.3
Operating income	\$ 45.1	\$ 140.5	\$ -	\$ 185.6
<b>2011</b>				
Operating revenues	\$880.1	\$1,167.1	\$(260.1)	\$1,787.1
Cost of goods sold	736.0	870.7	(260.1)	1,346.6
Gross margin on revenues	144.1	296.4	-	440.5
Other operation and maintenance	50.7	111.8	-	162.5
Depreciation and amortization	22.0	55.6	-	77.6
Impairment of assets	-	6.3	-	6.3
Gain on insurance proceeds	-	(3.0)	-	(3.0)
Taxes other than income	15.0	7.0	0.1	22.1
Operating income	\$ 56.4	\$ 118.7	\$ (0.1)	\$ 175.0
<b>2010</b>				
Operating revenues	\$984.8	\$1,005.6	\$(282.7)	\$1,707.7
Cost of goods sold	834.5	733.3	(282.7)	1,285.1
Gross margin on revenues	150.3	272.3	-	422.6
Other operation and maintenance	53.8	91.5	-	145.3
Depreciation and amortization	21.2	50.1	-	71.3
Impairment of assets	0.7	0.4	-	1.1
Taxes other than income	14.2	6.4	-	20.6
Operating income	\$ 60.4	\$ 123.9	\$ -	\$ 184.3

Operating Data

Year ended December 31	2012	2011	2010
Gathered volumes (TBtu/d) <sup>(A)</sup>	1.41	1.36	1.32
Incremental transportation volumes (TBtu/d) <sup>(B)</sup>	0.67	0.58	0.40
Total throughput volumes (TBtu/d)	2.08	1.94	1.72
Natural gas processed (TBtu/d)	0.98	0.79	0.82
Condensate sold (million gallons)	35	27	24
Average condensate sales price per gallon	\$1.95	\$2.09	\$1.81
NGLs sold – keep-whole (million gallons)	162	167	187
NGLs sold – purchased for resale (million gallons)	667	487	470
NGLs sold – percent-of-liquids (million gallons)	24	25	26
NGLs sold – percent-of-proceeds (million gallons)	14	6	5
Total NGLs sold (million gallons)	867	685	688
Average NGLs sales price per gallon	\$0.89	\$1.16	\$0.96
Average natural gas sales price per MMBtu	\$2.79	\$4.08	\$4.24

<sup>(A)</sup> Trillion British thermal units per day.

<sup>(B)</sup> Incremental transportation volumes consist of natural gas moved only on the transportation pipeline.

2012 Compared to 2011

Enogex's operating income increased \$10.6 million, or 6.1 percent, in 2012 as compared to 2011. This increase was primarily due to a higher gross margin, a higher gain on insurance proceeds related to the reimbursement of costs incurred to replace the damaged train at the Cox City natural gas processing plant discussed below and lower impairment of assets partially offset by higher other operation and maintenance expense, higher depreciation and amortization expense and higher taxes other than income. The higher gross margin related to (i) increased gathering rates and volumes associated with ongoing expansion projects and increased volumes from gas gathering assets acquired in November 2011 and August 2012 and (ii) increased inlet volumes resulting from the return to full service of the Cox City natural gas processing plant in September 2011, the South Canadian natural gas processing plant, which was placed in service in December 2011, and the Wheeler natural gas processing plant, which was placed in service in August 2012. These increases in gross margin were partially offset by lower average natural gas and NGLs prices. In 2012, imbalance volume changes and realized margin on physical gas long/short positions decreased the gross margin by \$7.5 million, net of corresponding imbalance and fuel tracker balances and the impact of the recovery of prior years' under-recovered fuel positions during 2012.

Other operation and maintenance expense increased \$10.4 million, or 6.4 percent, primarily due to:

- Increased payroll and benefits costs due to increased headcount to support business growth; and
- Increased rental expense on compression due to leases acquired in the August 2012 gas gathering acquisition partially offset by the reduction of rental payments on the Atoka plant, which was taken out of service in August 2011.

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

- Decreased costs for soil remediation projects; and
- Lower contract technical and professional services expense and materials and supplies expense due to a decrease in non-capital projects during 2012.

Depreciation and amortization expense increased \$31.2 million, or 40.2 percent, primarily due to additional assets placed in service throughout 2011 and 2012, including the gas gathering assets acquired in November 2011 and August 2012.

Impairment of assets decreased \$5.9 million, or 93.7 percent, primarily due to an impairment of \$5.0 million related to a management decision in August 2011 to use third-party processing exclusively for gathered volumes dedicated to the Atoka processing plant 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 was included in Net Income Attributable to Noncontrolling Interests in the Company's Consolidated Statement of Income.

Gain on insurance proceeds increased \$4.5 million related to the reimbursement of costs incurred to replace the damaged train at the Cox City natural gas processing plant.

Taxes other than income increased \$6.2 million, or 28.1 percent, primarily due to:

- Sales tax of \$3.5 million related to the acquisition of certain gas gathering assets in September 2012 as discussed in Note 3 of Notes to Consolidated Financial Statements; and
- Increased ad valorem taxes resulting from additional assets placed in service throughout 2011 and 2012.

#### Natural Gas Transportation and Storage

The natural gas transportation and storage business contributed \$134.6 million of Enogex's consolidated gross margin during 2012 as compared to \$144.1 million during 2011, a decrease of \$9.5 million or 6.6 percent. The transportation operations contributed \$110.1 million of Enogex's consolidated gross margin during 2012 as compared to \$118.8 million during 2011. The storage operations contributed \$24.5 million of Enogex's consolidated gross margin during 2012 as compared to \$25.3 million during 2011. Gross margin decreased primarily due to:

- Lower volumes and realized margin on sales of physical natural gas long positions associated with transportation operations, which decreased the gross margin by \$6.4 million, net of imbalances and fuel tracker balances;
- Lower storage fees due to terminated contracts and renegotiated contracts with less favorable terms, which decreased the gross margin by \$2.5 million;
- Lower gains on storage sales during 2012, which decreased the gross margin by \$1.9 million;
- Lower crosshaul revenues in 2012 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 during 2011 partially offset by increased utilization of \$1.3 million during 2012, which decreased the gross margin by \$1.7 million; and
- Lower transportation fees due to unbundling of transportation and gathering fees as contracts are renegotiated, which decreased the gross margin by \$1.4 million.

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

- Higher realized margin on hedging activity associated with natural gas storage inventory from storage, which increased the gross margin by \$4.4 million; and
- Higher transportation demand fees as a result of new contracts, which increased the gross margin by \$2.3 million.

Other operation and maintenance expense for the natural gas transportation and storage business was \$0.9 million, or 1.8 percent, lower during 2012 as compared to 2011 primarily due to lower contract technical and professional services expense and materials and supplies expense due to a decrease in non-capital projects during 2012 partially offset by increased payroll and benefits costs due to increased headcount to support business growth.

#### Natural Gas Gathering and Processing

The natural gas gathering and processing business contributed \$353.9 million of Enogex's consolidated gross margin during 2012 as compared to \$296.4 million during 2011, an increase of \$57.5 million, or 19.4 percent. The gathering operations contributed \$145.9 million of Enogex's consolidated gross margin during 2012 as compared to \$125.2 million during 2011. The processing operations contributed \$208.0 million of Enogex's consolidated gross margin during 2012 as compared to \$171.2 million during 2011.

During 2012, Enogex realized a higher gross margin in its natural gas gathering and processing operations related to (i) increased gathering rates and volumes associated with ongoing expansion projects, primarily in the Granite Wash play, which has added richer natural gas to Enogex's system, and increased volumes from gas gathering assets acquired in

November 2011 and August 2012, (ii) increased inlet volumes resulting from the return to full service of the Cox City natural gas processing plant in September 2011, the South Canadian natural gas processing plant, which was placed in service in December 2011, and the Wheeler natural gas processing plant, which was placed in service in August 2012, and (iii) contract conversion of one of Enogex's five largest customer's Oklahoma production volumes to fixed fee effective July 1, 2011. These increases in the gathering and processing gross margin were partially offset by lower average natural gas and NGLs prices.

The above factors contributed to the increase in the natural gas gathering and processing gross margin as follows:

- An increased gross margin on keep-whole processing of \$28.4 million;
- An increase in gathering fees associated with ongoing expansion projects and increased volumes from gas gathering assets, which increased the gross margin by \$16.8 million;
- An increase in condensate revenues associated with higher condensate margins and volumes, which increased the gross margin by \$14.2 million; and
- An increased gross margin on fixed-fee contracts of \$8.4 million.

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

- An increase in the utilization of third-party processing as a result of (i) the Atoka processing plant being taken out of service in August 2011 and (ii) increased activity from western Oklahoma and Texas Panhandle expansion projects currently processed by third parties, which together decreased the gross margin by \$6.2 million;
- A decrease in percent-of-liquids and percent-of-proceeds margins of \$4.4 million; and
- Lower volumes and realized margin on sales of physical natural gas long positions associated with gathering operations, which decreased the gross margin by \$1.1 million, net of imbalances and fuel tracker obligations.

Other operation and maintenance expense for the natural gas gathering and processing business was \$11.3 million, or 10.1 percent, higher during 2012 as compared to 2011 primarily due to:

- Increased payroll and benefits costs due to increased headcount to support business growth; and
- Increased rental expense on compression due to leases acquired in the August 2012 gas gathering acquisition partially offset by the reduction of rental payments on the Atoka plant, which was taken out of service in August 2011.

These increases in other operation and maintenance expense were partially offset by decreased costs for soil remediation projects.

#### Enogex Consolidated Information

*Other Income.* Enogex's consolidated other income was \$1.0 million during 2012 as compared to \$3.9 million during 2011, a decrease of \$2.9 million, or 74.4 percent, due to the recognition in April 2011 of a gain related to the sale of the Harrah processing plant and the associated Wellston and Davenport gathering assets.

*Other Expense.* Enogex's consolidated other expense was \$4.5 million during 2012 as compared to \$1.3 million during 2011, an increase of \$3.2 million due to higher non-cash losses on retirements of equipment during 2012.

*Interest Expense.* Enogex's consolidated interest expense was \$32.6 million during 2012 as compared to \$22.9 million during 2011, an increase of \$9.7 million, or 42.4 percent, primarily due to:

- A decrease in capitalized interest during 2012 due to the completion of several large capital projects as compared to 2011;
- Higher borrowings partially offset by repayments under Enogex's revolving credit agreement during 2012 as compared to 2011; and
- Borrowings under Enogex's term loan during 2012 with no comparable item during 2011.

*Income Tax Expense.* Enogex's consolidated income tax expense was \$45.7 million during 2012 as compared to \$51.7 million during 2011, a decrease of \$6.0 million, or 11.6 percent, primarily due to lower pre-tax income (net of noncontrolling interest) during 2012 as compared to 2011.

*Noncontrolling Interest.* Enogex's net income attributable to noncontrolling interest was \$29.7 million during 2012 as compared to \$20.8 million during 2011, an increase of \$8.9 million or 42.8 percent, due to higher net income, the ArcLight group's increased ownership in Enogex Holdings as a result of the ArcLight group funding capital contributions at a disproportionate percentage to OGE Holdings throughout 2011 and an impairment recorded in August 2011 related to the Atoka processing plant.

*Non-Recurring Items.* During 2012, Enogex had an increase in net income of \$4.6 million due to a gain on insurance proceeds related to the reimbursement of costs incurred to replace the damaged train at the Cox City natural gas processing plant partially offset by a decrease in net income of \$2.1 million related to sales taxes on the assets acquired in the gas gathering acquisitions in August 2012, as discussed in Note 3 of Notes to Consolidated Financial Statements, which Enogex does not consider to be reflective of its ongoing performance. During 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.

## 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 2011, imbalance 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 balances 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 a management decision in August 2011 to use third-party processing exclusively for gathered volumes dedicated to the Atoka processing plant 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 was 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.

## Natural Gas Transportation and Storage

The natural gas transportation and storage business contributed \$144.1 million of Enogex's gross margin in 2011 as compared to \$150.3 million in 2010, a decrease of \$6.2 million, or 4.1 percent. The transportation operations contributed \$118.8 million of Enogex's consolidated gross margin in 2011 as compared to \$116.9 million in 2010. The storage operations contributed \$25.3 million of Enogex's consolidated gross margin in 2011 as compared to \$33.4 million in 2010. Gross margin decreased primarily due to:

- 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;
- 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 \$4.4 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 in the natural gas transportation and storage gross margin were partially offset by:

- 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;
- More favorable results from Enogex's customer-focused risk management services, natural gas marketing activities and trading activities and the expiration of an unfavorable transportation contract, which increased the gross margin by \$2.2 million;
- Higher interruptible transportation fees due to new contracts with more favorable rates in 2011, which increased the gross margin by \$1.6 million; and
- 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.

Other operation and maintenance expense for the natural gas transportation and storage business was \$3.1 million, or 5.8 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.



### Natural Gas Gathering and Processing

The natural gas 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 natural gas 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. 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.

The above factors contributed to the increase in the natural gas gathering and processing gross margin as follows:

- An increase in condensate revenues associated with higher condensate prices and volumes, which increased the gross margin by \$11.1 million;
- An increase in gathering fees associated with ongoing expansion projects, which increased the gross margin by \$10.7 million;
- An increased gross margin on keep-whole processing of \$4.8 million;
- An increased gross margin on percent-of-liquids and percent-of-proceeds contracts of \$2.6 million; and
- An increased gross margin on fixed-fee contract of \$1.3 million.

These increases in the natural gas 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 natural gas 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.

### 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.* During 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 Enogex's natural gas storage inventory at the lower of cost or market value. The offsetting gains from the sale of withdrawals from inventory were realized during the first quarter of 2012.

#### Non-GAAP Financial Measure

Enogex has included in the Company's Form 10-K the non-GAAP financial measure EBITDA. EBITDA is a supplemental non-GAAP financial measure used by external users of the Company's financial statements such as investors, commercial banks and others, to assess:

- The financial performance of Enogex's assets without regard to financing methods, capital structure or historical cost basis;
- Enogex's operating performance and return on capital as compared to other companies in the midstream energy sector, without regard to financing or capital structure; and
- The viability of acquisitions and capital expenditure projects and the overall rates of return on alternative investment opportunities.

Enogex provides a reconciliation of EBITDA to net income attributable to Enogex Holdings, which Enogex considers to be its most directly comparable financial measure as calculated and presented in accordance with accounting principles generally accepted in the United States ("GAAP"). The non-GAAP financial measure of EBITDA should not be considered as an alternative to GAAP net income attributable to Enogex Holdings. EBITDA is not a presentation made in accordance with GAAP and has important limitations as an analytical tool. EBITDA should not be considered in isolation or as a substitute for analysis of Enogex's results as reported under GAAP. Because EBITDA excludes some, but not all, items that affect net income and is defined differently by different companies in Enogex's industry, Enogex's definition of EBITDA may not be comparable to a similarly titled measure of other companies.

To compensate for the limitations of EBITDA as an analytical tool, Enogex believes it is important to review the comparable GAAP measure and understand the differences between the measures.

(In millions)	2012	2011	2010
<b>Reconciliation of EBITDA to net income attributable to Enogex Holdings</b>			
Net income attributable to Enogex Holdings	\$147.8	\$155.9	\$476.1
Add:			
Interest expense, net	32.6	22.9	30.3
Income tax expense <sup>(A)</sup>	0.2	0.2	(325.0)
Depreciation and amortization expense <sup>(B)</sup>	111.6	77.2	70.2
<b>EBITDA</b>	<b>\$292.2</b>	<b>\$256.2</b>	<b>\$251.6</b>
<b>OGE Energy's portion</b>	<b>\$236.6</b>	<b>\$222.9</b>	<b>\$248.8</b>

<sup>(A)</sup> As of November 1, 2010, Enogex Holdings' earnings are no longer subject to tax (other than Texas state margin taxes) and are taxable at the individual partner level.

<sup>(B)</sup> Includes amortization of certain customer-based intangible assets associated with the acquisition from Cordillera in November 2011, which is included in gross margin for financial reporting purposes.

#### Off-Balance Sheet Arrangement

##### OG&E Railcar Lease Agreement

OG&E has a noncancellable operating lease with purchase options, covering 1,389 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.

On January 11, 2012, OG&E executed a five-year lease agreement for 135 railcars to replace railcars that have been taken out of service or destroyed. 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

##### Working Capital

Working capital is defined as the amount by which current assets exceed current liabilities. The Company's working capital requirements are driven generally by changes in accounts receivable, accounts payable, commodity prices, credit extended to, and the timing of collections from, customers, the level and timing of spending for maintenance and expansion activity, inventory levels and fuel recoveries.

The balance of Accounts Receivable, Net and Accrued Unbilled Revenues was \$352.7 million and \$381.8 million at December 31, 2012 and 2011, respectively, a decrease of \$29.1 million, or 7.6 percent, primarily due to a decrease in billings to OG&E's customers in 2012 due to milder weather in 2012, a decrease at Enogex due to lower natural gas sales volumes and prices and the timing of customer payments received partially offset by higher transmission revenue and increased rates at OG&E.

The balance of Accounts Payable was \$396.7 million and \$388.0 million at December 31, 2012 and 2011, respectively, an increase of \$8.7 million, or 2.2 percent, primarily due to increased NGLs volumes at Enogex partially offset by lower NGLs prices at Enogex, a decrease in accruals and the timing of ad valorem payments.

## Cash Flows

(In millions, year ended December 31)	2012	2011	2010	2012 vs. 2011		2011 vs. 2010	
				\$ Change	% Change	\$ Change	% Change
Net cash provided from operating activities	\$ 1,046.1	\$ 833.9	\$ 782.5	\$ 212.2	25.4 %	\$ 51.4	6.6%
Net cash used in investing activities	(1,192.6)	(1,395.8)	(846.1)	203.2	(14.6)%	(549.7)	65.0%
Net cash provided from financing activities	143.7	564.2	7.8	(420.5)	(74.5)%	556.4	*

\* Percentage is greater than 100 percent.

### Operating Activities

The increase of \$212.2 million, or 25.4 percent, in net cash provided from operating activities in 2012 as compared to 2011 was primarily due to:

- Higher fuel recoveries at OG&E in 2012 as compared to 2011;
- An increase in cash received in 2012 from transmission revenue and the recovery of investments including the Crossroads wind farm and smart grid partially offset by milder weather in 2012; and
- An increase in gathered volumes and NGLs volumes at Enogex during 2012 as compared to 2011 partially offset by lower natural gas and NGLs prices in 2012 as compared to 2011.

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.

These increases in net cash provided from operating activities was 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.

### Investing Activities

The decrease of \$203.2 million, or 14.6 percent, in net cash used in investing activities in 2012 as compared to 2011 was primarily due to lower levels of capital expenditures in 2012 related to the Crossroads wind farm at OG&E and lower levels of capital expenditures related to gathering and processing expansion projects at Enogex.

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 the Crossroads wind farm at OG&E and gathering and processing expansion projects at Enogex.

### Financing Activities

The decrease of \$420.5 million, or 74.5 percent, in net cash provided from financing activities in 2012 as compared to 2011 was primarily due to:

- Lower contributions from the ArcLight group during 2012 as compared to 2011;
- Higher borrowings under Enogex's revolving credit agreement during 2011; and
- Repayments of Enogex's line of credit during 2012.

These decreases in net cash provided from financing activities were partially offset by an increase in short-term debt borrowings during 2012 as compared to 2011.

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.

### 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 2013 through 2017 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.

(In millions)	2013	2014	2015	2016	2017
OG&E base transmission	\$ 65	\$ 50	\$ 50	\$ 50	\$ 50
OG&E base distribution	175	175	175	175	175
OG&E base generation	80	75	75	75	75
OG&E other	15	15	15	15	15
Total OG&E base transmission, distribution, generation and other	335	315	315	315	315
OG&E known and committed projects:					
Transmission projects:					
Balanced Portfolio 3E Projects <sup>(A)</sup>	205	25	–	–	–
SPP Priority Projects <sup>(B)</sup>	165	110	–	–	–
SPP Integrated Transmission Projects <sup>(C)</sup>	5	5	–	40	40
Total transmission projects	375	140	–	40	40
Other projects:					
Smart Grid Program	25	25	10	10	–
System Hardening	15	–	–	–	–
Environmental – low nitrogen oxide ("NOX") burners	30	20	25	20	–
Total other projects	70	45	35	30	–
Total OG&E known and committed projects	445	185	35	70	40
Total OG&E <sup>(D)</sup>	780	500	350	385	355
Enogex LLC base maintenance	50	55	55	55	55
Enogex LLC known and committed projects:					
Western Oklahoma/ Texas Panhandle gathering expansion	380	180	140	80	65
Other gathering expansion	25	15	10	10	10
Total Enogex LLC known and committed projects	405	195	150	90	75
Total Enogex LLC <sup>(E)</sup>	455	250	205	145	130
OGE Energy	10	10	10	10	10
Total capital expenditures	\$1,245	\$760	\$565	\$540	\$495

<sup>(A)</sup> Balanced Portfolio 3E includes three 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 \$175 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 southwesterly direction to the Oklahoma/Texas State line to a companion transmission line to be built by Southwestern Public Service to its Tuco substation at an estimated cost of \$115 million for OG&E, which is expected to be in service by mid-2014 and (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 \$45 million for OG&E, which was placed in service in February 2013.

<sup>(B)</sup> 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. OG&E began construction on the Hitchland project in November 2012 and expects to begin construction on the Kansas project in June 2013.

<sup>(C)</sup> On January 31, 2012, the SPP approved the Integrated Transmission Plan Near Term and Integrated Transmission Plan 10-year projects. These plans include two projects to be built by OG&E: (i) construction of 47 miles of transmission line from OG&E's Gracemont substation in a northwestern direction to a companion transmission line to be built by American Electric Power to its Elk City substation at an estimated cost of \$75 million for OG&E, which is expected to be in service by early 2012, and (ii) construction of 126 miles of transmission line from OG&E's Woodward District Extra High Voltage substation in a southeastern direction to OG&E's Cimarron substation and construction of a new substation on this transmission line, the Mathewson substation, at an estimated cost of \$210 million for OG&E, which is expected to be in service by early 2021. On April 9, 2012, OG&E received a notice to construct these projects from the SPP. On June 26, 2012, OG&E responded to the SPP that OG&E will construct the projects discussed above and is moving forward with more detailed cost estimates that must be reviewed and approved by the SPP. OG&E and American Electric Power are currently in discussions regarding how much of the 94 mile Elk City to Gracemont transmission line will be built by OG&E and American Electric Power. American Electric Power has argued for a larger portion of such transmission line than the traditional 50 percent split. The capital expenditures related to these projects are presented in the summary of capital expenditures for known and committed projects above.

<sup>(D)</sup> The capital expenditures above exclude any environmental expenditures associated with:

- Pollution control equipment related to controlling sulfur dioxide ("SO<sub>2</sub>") emissions under the regional haze requirements due to the uncertainty regarding the approach and timing for such pollution control equipment. The SO<sub>2</sub> emissions standards in the U.S. Environmental Protection Agency's ("EPA") Federal implementation plan ("FIP") 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 FIP is being challenged by OG&E and the state of Oklahoma. On June 22, 2012, OG&E was granted a stay of the FIP by the U.S. Court of Appeals for the Tenth Circuit, which delays the timing of required implementation of the SO<sub>2</sub> emissions standards in the rule. The merits of the appeal have been fully briefed, and oral argument is scheduled to occur on March 6, 2013. Neither the outcome of the challenge to the FIP nor the timing of any required capital expenditures can be predicted with any certainty at this time, but such capital expenditures could be significant.
- Installation of control equipment for compliance with Mercury and Air Toxics Standards ("MATS") by a deadline of April 16, 2015, with the possibility of a one-year extension. OG&E is currently planning to utilize activated carbon injection and low levels of dry sorbent injection at each of its five coal-fired units. Due to various uncertainties about the final design, the potential use of this technology relating to regional haze measures and the specifications for the control equipment, the resulting cost estimates currently range from \$34 million to \$72 million per unit.

OG&E is currently evaluating options to comply with environmental requirements. For further information, see "Environmental Laws and Regulations" below.

<sup>(E)</sup> 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.

Additional capital expenditures beyond those identified in the table above, 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 above reflect base market conditions at February 27, 2013 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 above.

## Contractual Obligations

The following table summarizes the Company's contractual obligations at December 31, 2012. See the Company's Consolidated Statements of Capitalization and Note 16 of Notes to Consolidated Financial Statements for additional information.

(In millions)	2013	2014-2015	2016-2017	After 2017	Total
Maturities of long-term debt <sup>(A)</sup>	\$ 0.2	\$ 550.4	\$ 235.4	\$ 2,070.1	\$ 2,856.1
Operating lease obligations					
OG&E railcars	3.2	5.5	27.3	–	36.0
OG&E wind farm land leases	2.0	4.2	4.5	51.2	61.9
OG&E Energy noncancellable operating lease	0.3	1.6	1.6	0.7	4.2
Enogex noncancellable operating leases	5.2	7.2	4.1	–	16.5
Total operating lease obligations	10.7	18.5	37.5	51.9	118.6
Other purchase obligations and commitments					
OG&E cogeneration capacity and fixed operation and maintenance payments	87.9	170.3	162.5	315.3	736.0
OG&E expected cogeneration energy payments	58.6	134.3	168.3	468.7	829.9
OG&E minimum fuel purchase commitments	405.0	519.8	–	–	924.8
OG&E expected wind purchase commitments	57.5	116.9	120.6	838.0	1,133.0
OG&E long-term service agreements	8.0	34.5	12.6	53.0	108.1
EER commitments	11.9	15.5	0.8	–	28.2
Total other purchase obligations and commitments	628.9	991.3	464.8	1,675.0	3,760.0
Total contractual obligations	639.8	1,560.2	737.7	3,797.0	6,734.7
Amounts recoverable through fuel adjustment clause <sup>(B)</sup>	(524.3)	(776.5)	(316.2)	(1,306.7)	(2,923.7)
Total contractual obligations, net	\$ 115.5	\$ 783.7	\$ 421.5	\$ 2,490.3	\$ 3,811.0

<sup>(A)</sup> Maturities of the Company's long-term debt during the next five years consist of \$0.2 million, \$300.2 million, \$250.2 million, \$110.2 million and \$125.2 million in years 2013, 2014, 2015, 2016 and 2017, respectively.

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

OG&E also has 440 megawatts ("MW") 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 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, 2012, 42.3 percent of the qualified defined benefit retirement plan ("Pension Plan") investments were in listed common stocks with the balance primarily invested in U.S Government securities, bonds, debentures and notes, a commingled fund and a common collective trust as presented in Note 14 of Notes to Consolidated Financial Statements. In 2012, asset returns on the Pension Plan were 10.6 percent due to the gains in fixed income and equity investments. During the same time, corporate bond yields, which are used in determining the discount rate for future pension obligations, have continued to decline. During 2012 and 2011, OGE Energy made contributions to its Pension Plan of \$35 million and \$50 million, respectively, 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 2013, OGE Energy expects to 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 supplemental retirement plan to the Pension Plan ("Restoration of Retirement Income Plan") and the postretirement benefit plans at December 31, 2012 and 2011. 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.

(In millions, year ended December 31)	Pension Plan		Restoration of Retirement Income Plan		Postretirement Benefit Plans	
	2012	2011	2012	2011	2012	2011
Benefit obligations	<b>\$(747.1)</b>	\$(697.7)	<b>\$(14.5)</b>	\$(13.3)	<b>\$(301.0)</b>	\$(280.6)
Fair value of plan assets	<b>626.0</b>	589.8	-	-	<b>59.6</b>	61.0
Funded status at end of year	<b>\$(121.1)</b>	\$(107.9)	<b>\$(14.5)</b>	\$(13.3)	<b>\$(241.4)</b>	\$(219.6)

### 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 November 2012 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 \$0.4175 per share from \$0.3925 per share effective with the Company's first quarter 2013 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	F2

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 rating 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 could also lead to higher long-term borrowing costs and, if below investment grade, would require the Company to post 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, 2012, the Company would have been required to post \$0.2 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, 2012. 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 June 20, 2012, Fitch Ratings downgraded OGE Energy Corp.'s short-term debt rating from F1 to F2 and OGE Energy Corp.'s long-term debt issuer default rating from A to A-. All other ratings (by Fitch Ratings) at OG&E and Enogex remained unchanged and with a stable outlook. Fitch Ratings indicated that the downgrade at OGE Energy Corp. was primarily due to concerns related to the uncertainties associated with the environmental mandates at OG&E as well as Enogex's sensitivity to commodity prices and growth strategy with the ArcLight group.

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.

### 2012 Capital Requirements, Sources of Financing, Purchase of Treasury Stock and Financing Activities

Total capital requirements, consisting of capital expenditures and maturities of long-term debt, were \$1,351.8 million and contractual obligations, net of recoveries through fuel adjustment clauses, were \$112.8 million resulting in total net capital requirements and contractual obligations of \$1,464.6 million in 2012, of which \$12.9 million was to comply with environmental regulations. This compares to net capital requirements of \$1,446.2 million and net contractual obligations of \$111.1 million totaling \$1,557.3 million in 2011, of which \$6.9 million was to comply with environmental regulations.

In 2012, the Company's sources of capital were cash generated from operations, proceeds from the issuance of short-term debt, proceeds from Enogex's term loan agreement, 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 "Working Capital" for a discussion of significant changes in net working capital requirements as it pertains to operating cash flow and liquidity.

#### **Purchase of Treasury Stock**

In November 2012, the Company purchased 60,000 shares of its common stock at an average cost of \$55.41 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 2013. The Company expects to purchase shares in the future to satisfy a portion of its obligation under its incentive plan.

#### **Enogex Term Loan Agreement**

On August 2, 2012, Enogex entered into a \$250 million, three-year term loan agreement with a maturity date of August 2, 2015. The loan was used to fund capital expenditures and for working capital purposes.

#### **Potential Collateral Requirements**

Derivative instruments are utilized in managing the Company's commodity price exposures and in Enogex's asset management 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 the Dodd-Frank Act. Among other things, the Dodd-Frank Act provides for a new regulatory regime for derivatives, including mandatory clearing of certain swaps and margin requirements. The Dodd-Frank Act contains provisions that should exempt certain derivatives end-users such as the Company from much of the clearing requirements. The regulations require that the decision on whether to use the end-user exception from mandatory clearing for derivative transactions be reviewed and approved by an "appropriate committee" of the Board of Directors. The scope of the margin requirements and their potential direct impact on the Company remain unclear because final rules have not been issued. Further, even if the Company qualifies for the end-user exception to clearing and margin requirements are not imposed on end-users, its derivative counterparties may be subject to new capital, margin and business conduct requirements as a result of the new regulations, which may increase the Company's transaction costs or make it more difficult to enter into derivative transactions

on favorable terms. The Company's inability to enter into derivative 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. The impact of the provisions of the Dodd-Frank Act on the Company cannot be fully determined at this time due to uncertainty over forthcoming regulations and potential changes to the derivatives markets arising from new regulatory requirements.

#### **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. The Company has revolving credit facilities totaling in the aggregate \$1,550.0 million. These bank facilities can also be used as letter of credit facilities. The short-term debt balance was \$430.9 million and \$277.1 million at December 31, 2012 and 2011, respectively. The weighted-average interest rate on short-term debt at December 31, 2012 was 0.43 percent. The average balance of short-term debt in 2012 was \$451.0 million at a weighted-average interest rate of 0.45 percent. The maximum month-end balance of short-term debt in 2012 was \$608.2 million. At December 31, 2012, Enogex had no outstanding borrowings under its revolving credit agreement as compared to \$150.0 million at December 31, 2011. 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, 2012, the Company had \$1,116.9 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, 2013 and ending December 31, 2014. At December 31, 2012, the Company had \$1.8 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 up to \$250 million of long-term debt in the first half of 2013, 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 \$12 million and \$15 million of common stock in its Automatic Dividend Reinvestment and Stock Purchase Plan in 2013. 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 determination of Pension Plan assumptions, impairment estimates of long-lived assets (including intangible assets), 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 segment and the natural gas gathering and processing segment, 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, amortization methodologies related to intangible assets

and impairment assessments of goodwill. 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 a significant amount 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 a significant amount 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	+/- 1 percent	+/- \$6.3 million
Discount rate	+/- 0.25 percent	+/- \$16.7 million
Contributions	+/- \$10 million	+/- \$10 million

#### Assessing 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 of Notes to Consolidated Financial Statements), related to the Atoka processing plant. The Company recorded no other material impairments in 2012, 2011 or 2010.

As a result of the gas gathering acquisitions in November 2011, Enogex recorded goodwill of \$39.4 million. Enogex assesses its goodwill for impairment at least annually as of October 1 by comparing the fair value of the reporting unit with its book value, including goodwill. Enogex utilizes the income approach (generally accepted valuation approach) to estimate the fair value of the reporting unit, also giving consideration to alternative methods such as the market and cost approaches. Under the income approach, anticipated cash flows over a period of years plus a terminal value are discounted to present value using appropriate discount rates. Enogex performs its goodwill impairment testing at the natural gas gathering and processing segment reporting unit level. Enogex recorded no impairments of goodwill in 2012.

#### **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 or claims made by third parties, including governmental 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 disclosed otherwise in this Form 10-K, the Company believes that any reasonably possible losses in excess of accrued amounts arising out of pending or threatened lawsuits or claims would not be quantitatively material to its financial statements and would not 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 three months to 74 years. The Company also has certain asset retirement obligations primarily related to Enogex's processing plants and compression sites that have not been recorded because the Company cannot determine when these obligations will be incurred. The inputs used in the valuation of asset retirement obligations include the assumed life of the asset placed into service, the average inflation rate, market risk premium, the credit-adjusted risk free interest rate and the timing of incurring costs related to the retirement of the asset.

#### **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 operations and natural gas transportation 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, 2012 mature by the end of the first quarter of 2013.

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, 2012, 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, 2012 and 2011, Accrued Unbilled Revenues were \$57.4 million and \$59.3 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. Also, a portion of the uncollectible provision related to fuel is being recovered through the fuel adjustment clause. At December 31, 2012, if the provision rate were to increase or decrease by 10 percent, this would cause a change in the uncollectible expense recognized of \$0.3 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 \$2.6 million and \$3.7 million at December 31, 2012 and 2011, respectively.

### **Natural Gas Transportation and Storage and Natural Gas Gathering and Processing Segments Operating Revenues**

Operating revenues for gathering, processing, transportation and storage 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 and storage 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 natural gas gathering and processing volumes on the Oklahoma portion of Enogex's system. As a result, Enogex has recorded \$7.1 million in Deferred Revenues on the Company's Consolidated Balance Sheet at December 31, 2012, which are expected to be recognized based on the estimated average fee per MMBtu processed by the end of 2014. Enogex has also recorded \$1.5 million in Deferred Revenues on the Company's Consolidated Balance Sheet at December 31, 2012 in connection with other gathering and processing agreements.

Enogex engages in asset management and hedging activities related to the purchase and sale of natural gas and NGLs. Contracts utilized in these activities generally include purchases and sales for physical delivery, over-the-counter forward swap and options contracts and exchange traded futures and options. Enogex'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**

Enogex utilizes purchases and sales for physical delivery, over-the-counter forward swap and options contracts and exchange traded futures and options. These activities either qualify as derivatives and are recorded at fair market value or qualify for normal purchase normal sale treatment. Enogex'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. 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, 2012, unrealized mark-to-market losses were \$0.2 million, none of which were calculated utilizing models. At December 31, 2012, 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 and 2012, Enogex completed gas gathering acquisitions accounted for as business combinations as discussed in Note 3 of Notes to Consolidated Financial Statements. As part of these acquisitions, Enogex has 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. Intangible assets are amortized on a straight-line basis over their useful lives 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 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 asset management activity, Enogex injects and withdraws natural gas into and out of inventory under the terms of its storage capacity contracts. During the years ended December 31, 2012, 2011 and 2010, Enogex recorded write-downs to market value related to natural gas storage inventory of \$5.5 million, \$4.8 million and \$0.3 million, respectively. The amount of Enogex's natural gas inventory was \$16.5 million and \$23.7 million at December 31, 2012 and 2011, 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 natural gas transportation and storage and natural gas gathering and processing segments was less than \$0.1 million at December 31, 2012 and 2011.

### **Accounting Pronouncements**

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

### **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 or claims made by third parties, including governmental 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. At the present time, based on currently available information, except as disclosed otherwise in this Form 10-K, the Company believes that any reasonably possible losses in excess of accrued amounts arising out of pending or threatened lawsuits or claims would not be quantitatively material to its financial statements and would not 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 significant future capital 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.

It is estimated that OG&E's and Enogex's total expenditures to comply with environmental laws, regulations and requirements for 2013 will be \$63.0 million and \$6.4 million, respectively, of which \$45.3 million and \$0.7 million, respectively, are for capital expenditures. It is estimated that OG&E's and Enogex's total expenditures to comply for environmental laws, regulations and requirements for 2014 will be \$37.7 million and \$6.3 million, respectively, of which \$19.2 million and \$0.5 million, respectively, are for capital expenditures. The amounts for OG&E above include capital expenditures for low NOX burners and exclude certain other capital expenditures as discussed in the capital expenditures table and related footnote D in "Future Capital Requirements and Financing Activities" above. The Company's management believes that all of its operations are in substantial compliance with current Federal, state and local environmental standards. 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. The regional haze rule is 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 rule. 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 with overfire air (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 capital cost of installing and operating these NOX controls on all covered units, based on recent industry experience and past projects, will be approximately \$95 million. With respect to SO2 emissions, the SIP included an agreement between the Oklahoma Department of Environmental Quality and OG&E that established BART for SO2 control at the four affected 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 issued a final rule in which it rejected portions of the Oklahoma SIP and issued a FIP in their place. While the EPA accepted Oklahoma's BART determination for NOX in the final rule, it rejected Oklahoma's SO2 BART determination with respect to the four coal-fired units at the Sooner and Muskogee generating stations. The EPA is instead 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 include capital costs to OG&E of more than \$1.0 billion. OG&E and the state of Oklahoma filed an administrative stay request with the EPA on February 24, 2012. The EPA has not yet responded to this request. OG&E and other parties also filed a petition for review of the FIP in the U.S. Court of Appeals for the Tenth Circuit on February 24, 2012 and a stay request on April 4, 2012. On June 22, 2012, the U.S. Court of Appeals for the Tenth Circuit granted the stay request. The stay will remain in place until a decision on the petition for review is complete, which will delay the implementation of the regional haze rule in Oklahoma. The merits of the appeal have been fully briefed and oral argument is scheduled to occur on March 6, 2013. Neither the outcome of the appeal nor the timing 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 would require 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 would make 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 would have been required to reduce ozone-season NOX emissions from its electrical generating units within the state beginning in 2012. The Cross-State Air Pollution Rule was 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, which includes the supplemental rule, pending a decision on the merits. By order dated August 21, 2012, the U.S. Court of Appeals vacated the Cross-State Air Pollution Rule and ordered the EPA to promulgate a replacement rule. On January 25, 2013, the U.S. Court of Appeals denied the EPA's request for an en banc reconsideration of the court's decision vacating the rule. OG&E cannot predict the outcome of such challenges.

#### Hazardous Air Pollutants Emission Standards

On April 16, 2012, regulations governing emissions of certain hazardous air pollutants from electric generating units were published as the final MATS rule. This 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 the possibility of a one-year extension. To comply with this rule, OG&E is currently planning to utilize activated carbon injection and low levels of dry sorbent injection at each of its five coal-fired units. Due to various uncertainties about the final design, the potential use of this technology relating to regional haze measures and the specifications for the control equipment, the resulting cost estimates currently range from \$34 million to \$72 million per unit. OG&E is evaluating the results of field testing to finalize cost estimates and implementation schedules. The final MATS rule has been appealed by several parties. OG&E is not a party to the appeals and cannot predict the outcome of any such appeals.

#### 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. On May 1, 2012, OG&E responded to the EPA's supplemental request for information. 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 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. 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. The cost of any required pollution control equipment could also be significant.

#### 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. The Clean Air Act requires the EPA to review each NAAQS every five years. As a result of these reviews, the EPA periodically has taken action to adopt more stringent NAAQS for those pollutants. If any areas of Oklahoma were to be designated as not attaining the NAAQS for a particular pollutant, the Company could be required to install additional emission controls on its facilities to help the state achieve attainment with the NAAQS. As of the end of 2012, no areas of Oklahoma had been designated as non-attainment for pollutants that are likely to affect the Company's operations. Several processes are under way to designate areas in Oklahoma as attaining or not attaining revised NAAQS. The Company is monitoring those processes and their possible impact on its operations but, at this time, cannot determine with any certainty whether they will cause a material impact to the Company's financial results.

#### 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 SO<sub>2</sub> and NO<sub>x</sub> 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 SO<sub>2</sub> from the chimney during or after a specified year. For each ton of SO<sub>2</sub> 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 NO<sub>x</sub>, coal-fired electric utility boilers. As with the SO<sub>2</sub> emission reduction requirements, the NO<sub>x</sub> program was implemented in two phases, beginning in 1996 and 2000. The NO<sub>x</sub> program embodies many of the same principles of the SO<sub>2</sub> trading program. However, it does not cap NO<sub>x</sub> emissions as the SO<sub>2</sub> 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

There is continuing discussion and evaluation of possible global climate change in certain regulatory and legislative arenas. The focus is generally on emissions of greenhouse gases, including carbon dioxide, sulfur hexafluoride and methane, and whether these emissions are contributing to the 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, but the EPA has existing authority under the Clean Air Act to regulate greenhouse gas emissions from stationary sources. 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. 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 the Company's facilities, this could result in significant additional compliance costs that would affect the Company's future financial position, results of operations and cash flows if such costs are not recovered through regulated rates.

Following from the Supreme Court's interpretation of the Clean Air Act's applicability to greenhouse gases in *Massachusetts v. EPA*, the EPA has proposed regulations for new power plants. In 2010, the EPA also issued a final rule that makes certain existing sources subject to permitting requirements for greenhouse gas emissions. This rule 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 that undergo construction or modification may have to install best available control technology to control greenhouse gas emissions. Although these rules currently do not have a material impact on the Company's existing facilities, they ultimately 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.

In 2009, the EPA adopted a 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. OG&E also reports quarterly its carbon dioxide emissions from generating units subject to the Federal Acid Rain Program. OG&E and Enogex have submitted the reports required by the applicable reporting rules.

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

The Company also seeks to utilize renewable energy sources that do not emit greenhouse gases. OG&E's service territory is in central Oklahoma and borders one of the nation's best wind resource areas. The Company has leveraged its advantageous geographic position to develop renewable energy resources and transmission to deliver the renewable energy. The SPP has begun to authorize the construction 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 limitations.

#### 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 become subject to protection, the Company's operations and development projects, particularly transmission, wind or pipeline projects, could be restricted or delayed, or the Company could be required to implement expensive mitigation measures. The U.S. Fish and Wildlife Service announced a proposed rule to list the lesser prairie chicken as threatened on November 30, 2012. A final decision regarding listing is anticipated to be completed by September 30, 2013. Although the lesser prairie chicken and its habitat are located in potential development areas of the Company, the impact of a final decision to list this species as threatened cannot be determined at this time.

## **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 no definitive timetable for issuing a final rule regarding the regulation of coal ash can be provided.

The Company has sought and will continue to seek pollution prevention opportunities and to evaluate the effectiveness of its waste reduction, reuse and recycling efforts. In 2012, the Company obtained refunds of \$6.4 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. In June 2012, the EPA published a Notice of Data Availability requesting additional comments on a number of impingement mortality-related issues based on new information received during the initial public comment period. On July 11, 2012, OG&E filed comments regarding the Notice of Data Availability. In July 2012, the EPA entered into a settlement agreement in a pending litigation matter, which extended the deadline by which the proposed rules will be finalized to June 2013. 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 Board of Directors appoints the Chief Risk Officer of the Company. The Chief Risk Officer serves as chairman of the Company's Risk Oversight Committee, which consists primarily of corporate officers, and 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. On a quarterly basis, the Risk Oversight Committee, through the Chief Risk Officer, reports to the Audit Committee of the Company's Board of Directors on the Company's risk profile affecting anticipated financial results, including any significant risk issues.

The Enogex 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 or by calculating the net present value of the monthly payments discounted by the Company's current borrowing rate. 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)	2013	2014	2015	2016	2017	Thereafter	Total	12/31/12 Fair Value
<b>Fixed-rate debt<sup>(A)</sup></b>								
Principal amount	\$ 0.2	\$300.2	\$ 0.2	\$110.2	\$125.2	\$1,934.7	\$2,470.7	\$3,011.3
Weighted-average interest rate	2.71%	6.25%	2.71%	5.15%	6.49%	6.38%	6.31%	
<b>Variable-rate debt<sup>(B)</sup></b>								
Principal amount	\$ -	\$ -	\$250.0	\$ -	\$ -	\$ 135.4	\$ 385.4	\$ 385.4
Weighted-average interest rate	-	-	1.72%	-	-	0.24%	1.20%	

<sup>(A)</sup> 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.

<sup>(B)</sup> A hypothetical change of 100 basis points in the underlying variable interest rate incurred by the Company would change interest expense by \$3.9 million annually.

**Commodity Price Risk**

Commodity price risk is present in the Company's 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 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 utilizes derivatives and other forward transactions to mitigate the effects these market fluctuations have on the Company's operating income. Because the commodities covered by these transactions 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. 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 positions; therefore, the value of 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 decline in quoted market prices. The result of this analysis, which may differ from actual results, reflects net commodity price risk to be \$21.6 million at December 31, 2012. 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)	2012	2011	2010
<b>Operating revenues</b>			
Electric Utility operating revenues	\$2,141.2	\$2,211.5	\$2,109.9
Natural Gas Midstream Operations operating revenues	1,530.0	1,704.4	1,607.0
Total operating revenues	3,671.2	3,915.9	3,716.9
Cost of goods sold (exclusive of depreciation and amortization shown below)			
Electric Utility cost of goods sold	819.0	966.0	952.6
Natural Gas Midstream Operations cost of goods sold	1,099.7	1,311.9	1,234.8
Total cost of goods sold	1,918.7	2,277.9	2,187.4
Gross margin on revenues	1,752.5	1,638.0	1,529.5
Operating expenses			
Other operation and maintenance	601.5	581.2	549.8
Depreciation and amortization	371.0	307.1	291.3
Impairment of assets	0.4	6.3	1.1
Gain on insurance proceeds	(7.5)	(3.0)	–
Taxes other than income	110.2	99.7	93.4
Total operating expenses	1,075.6	991.3	935.6
Operating income	676.9	646.7	593.9
Other income (expense)			
Interest income	0.6	0.5	–
Allowance for equity funds used during construction	6.2	20.4	11.4
Other income	17.0	19.3	13.7
Other expense	(16.5)	(21.7)	(17.9)
Net other income	7.3	18.5	7.2
Interest expense			
Interest on long-term debt	158.9	146.1	139.3
Allowance for borrowed funds used during construction	(3.5)	(10.4)	(5.5)
Interest on short-term debt and other interest charges	8.7	5.2	5.9
Interest expense	164.1	140.9	139.7
Income before taxes	520.1	524.3	461.4
Income tax expense	135.1	160.7	161.0
Net income	385.0	363.6	300.4
Less: net income attributable to noncontrolling interests	30.0	20.7	5.1
<b>Net income attributable to OGE Energy</b>	<b>\$ 355.0</b>	<b>\$ 342.9</b>	<b>\$ 295.3</b>
Basic average common shares outstanding	98.6	97.9	97.3
Diluted average common shares outstanding	99.1	99.2	98.9
Basic earnings per average common share attributable to OGE Energy common shareholders	\$ 3.60	\$ 3.50	\$ 3.03
Diluted earnings per average common share attributable to OGE Energy common shareholders	\$ 3.58	\$ 3.45	\$ 2.99
Dividends declared per common share	\$ 1.5950	\$ 1.5175	\$ 1.4625

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

## CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(In millions, year ended December 31)	2012	2011	2010
<b>Net income</b>	<b>\$385.0</b>	<b>\$363.6</b>	<b>\$300.4</b>
Other comprehensive income (loss), net of tax			
Pension plan and restoration of retirement income plan:			
Amortization of deferred net loss, net of tax of \$1.7, \$1.4 and \$1.2, respectively	<b>3.0</b>	2.5	1.3
Net gain (loss) arising during the period, net of tax of (\$5.6), (\$6.7) and \$4.4, respectively	<b>(10.2)</b>	(13.5)	7.6
Amortization of prior service cost, net of tax of \$0.2, \$0.2 and \$0.1, respectively	<b>0.2</b>	0.4	0.2
Postretirement plans:			
Amortization of deferred net loss, net of tax of (\$1.1), (\$1.6) and \$0.6, respectively	<b>2.0</b>	1.8	1.2
Net loss arising during the period, net of tax of (\$1.1), (\$3.1) and (\$2.4), respectively	<b>(2.3)</b>	(3.6)	(4.1)
Amortization of deferred net transition obligation, net of tax of \$0.1, \$0.1 and \$0.1, respectively	<b>0.1</b>	0.2	0.1
Amortization of prior service cost, net of tax of (\$1.0), (\$1.6) and \$0.1, respectively	<b>(1.8)</b>	(1.8)	-
Prior service credit arising during the period, net of tax of \$0, \$9.5 and \$0, respectively	<b>-</b>	10.8	-
Deferred commodity contracts hedging (gains) losses reclassified in net income, net of tax of (\$1.6), \$12.6 and \$9.9, respectively	<b>(3.6)</b>	27.6	18.5
Deferred commodity contracts hedging gains (losses), net of tax of \$0.1, (\$1.7) and (\$8.5), respectively	<b>0.4</b>	(4.8)	(16.3)
Amortization of deferred interest: rate swap hedging losses, net of tax of \$0.2, \$0.2 and \$0.2, respectively	<b>0.2</b>	0.3	0.2
Other comprehensive income (loss), net of tax	<b>(12.0)</b>	19.9	8.7
Comprehensive income (loss)	<b>373.0</b>	<b>383.5</b>	<b>309.1</b>
Less: Comprehensive income attributable to noncontrolling interest for sale of equity investment	<b>(0.5)</b>	(3.2)	(6.2)
Less: Comprehensive income attributable to noncontrolling interests	<b>27.0</b>	24.2	5.5
<b>Total comprehensive income attributable to OGE Energy</b>	<b>\$346.5</b>	<b>\$362.5</b>	<b>\$309.8</b>

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

## CONSOLIDATED STATEMENTS OF CASH FLOWS

(In millions, year ended December 31)	2012	2011	2010
<b>Cash flows from operating activities</b>			
Net income	\$ 385.0	\$ 363.6	\$ 300.4
Adjustments to reconcile net income to net cash provided from operating activities			
Depreciation and amortization	374.8	307.7	291.3
Impairment of assets	0.4	6.3	1.1
Deferred income taxes and investment tax credits, net	143.7	166.0	146.4
Allowance for equity funds used during construction	(6.2)	(20.4)	(11.4)
(Gain) loss on disposition and abandonment of assets	4.2	(2.7)	-
Gain on insurance proceeds	(7.5)	(3.0)	-
Stock-based compensation	(2.6)	7.8	7.4
Excess tax benefit on stock-based compensation	-	-	(0.7)
Price risk management assets	3.3	(1.7)	3.9
Price risk management liabilities	(4.6)	19.0	8.5
Regulatory assets	20.3	14.0	24.1
Regulatory liabilities	(14.8)	(1.9)	(12.4)
Other assets	(6.9)	(7.6)	6.3
Other liabilities	(14.3)	(37.4)	(37.0)
Change in certain current assets and liabilities			
Accounts receivable, net	27.1	(48.0)	11.9
Accrued unbilled revenues	1.9	(2.5)	0.4
Income taxes receivable	1.1	(3.6)	153.0
Fuel, materials and supplies inventories	13.7	54.2	(45.2)
Gas imbalance assets	(7.2)	0.7	0.7
Fuel clause under recoveries	1.8	(0.8)	(0.7)
Other current assets	(4.7)	(7.2)	(5.9)
Accounts payable	25.1	34.5	59.2
Gas imbalance liabilities	(4.8)	3.1	(5.3)
Fuel clause over recoveries	101.5	(22.2)	(157.6)
Other current liabilities	15.8	16.0	44.1
Net cash provided from operating activities	<b>1,046.1</b>	<b>833.9</b>	<b>782.5</b>
<b>Cash flows from investing activities</b>			
Capital expenditures (less allowance for equity funds used during construction)	(1,150.6)	(1,270.4)	(879.9)
Acquisition of gathering assets	(78.6)	(200.4)	-
Proceeds from sale of assets	1.5	18.0	2.3
Proceeds from insurance	7.6	7.4	-
Reimbursement of capital expenditures	27.5	49.6	31.5
Net cash used in investing activities	<b>(1,192.6)</b>	<b>(1,395.8)</b>	<b>(846.1)</b>
<b>Cash flows from financing activities</b>			
Proceeds from long-term debt	250.0	246.3	246.2
Increase (decrease) in short-term debt	153.8	132.1	(30.0)
Contributions from noncontrolling interest partners	46.2	216.4	183.2
Issuance of common stock	14.3	14.8	16.9
Proceeds from line of credit	-	150.0	115.0
Retirement of long-term debt	-	-	(289.2)
Excess tax benefit on stock-based compensation	-	-	0.7
Payment of long-term debt	(0.1)	-	-
Purchase of treasury stock	(3.4)	(6.2)	-
Distributions to noncontrolling interest partners	(12.6)	(17.4)	(4.0)
Repayment of line of credit	(150.0)	(25.0)	(90.0)
Dividends paid on common stock	(154.5)	(146.8)	(141.0)
Net cash provided from financing activities	<b>143.7</b>	<b>564.2</b>	<b>7.8</b>
Net increase (decrease) in cash and cash equivalents	<b>(2.8)</b>	<b>2.3</b>	<b>(55.8)</b>
Cash and cash equivalents at beginning of period	<b>4.6</b>	<b>2.3</b>	<b>58.1</b>
Cash and cash equivalents at end of period	<b>\$ 1.8</b>	<b>\$ 4.6</b>	<b>\$ 2.3</b>

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

## CONSOLIDATED BALANCE SHEETS

(In millions, December 31)	2012	2011
<b>Assets</b>		
<b>Current assets</b>		
Cash and cash equivalents	\$ 1.8	\$ 4.6
Accounts receivable, less reserve of \$2.6 and \$3.8, respectively	295.3	322.5
Accrued unbilled revenues	57.4	59.3
Income taxes receivable	7.2	8.3
Fuel inventories	93.3	100.7
Materials and supplies, at average cost	80.9	87.2
Price risk management	0.5	3.5
Gas imbalances	9.0	1.8
Deferred income taxes	187.7	32.1
Fuel clause under recoveries	-	1.8
Assets held for sale	25.5	-
Other	35.6	30.9
<b>Total current assets</b>	<b>794.2</b>	<b>652.7</b>
Other property and investments, at cost	52.2	46.7
<b>Property, plant and equipment</b>		
In service	11,504.4	10,315.9
Construction work in progress	387.5	499.0
<b>Total property, plant and equipment</b>	<b>11,891.9</b>	<b>10,814.9</b>
Less accumulated depreciation	3,547.1	3,340.9
<b>Net property, plant and equipment</b>	<b>8,344.8</b>	<b>7,474.0</b>
<b>Deferred charges and other assets</b>		
Regulatory assets	510.6	507.9
Intangible assets, net	127.4	137.0
Goodwill	39.4	39.4
Price risk management	-	0.3
Other	53.6	48.0
<b>Total deferred charges and other assets</b>	<b>731.0</b>	<b>732.6</b>
<b>Total assets</b>	<b>\$ 9,922.2</b>	<b>\$ 8,906.0</b>

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

(In millions, December 31)

2012 2011

**Liabilities and stockholders' equity**

Current liabilities		
Short-term debt	\$ 430.9	\$ 277.1
Accounts payable	396.7	388.0
Dividends payable	41.2	38.5
Customer deposits	70.3	67.6
Accrued taxes	48.1	42.3
Accrued interest	55.0	54.8
Accrued compensation	55.2	47.8
Price risk management	0.3	0.4
Gas imbalances	5.0	9.8
Fuel clause over recoveries	109.2	7.7
Other	64.5	64.5
Total current liabilities	1,276.4	998.5
Long-term debt	2,848.6	2,737.1
Deferred credits and other liabilities		
Accrued benefit obligations	399.8	360.8
Deferred income taxes	1,948.8	1,651.4
Deferred investment tax credits	3.9	6.1
Regulatory liabilities	245.1	230.7
Deferred revenues	37.7	40.8
Price risk management	-	0.1
Other	89.5	61.2
Total deferred credits and other liabilities	2,724.8	2,351.1
Total liabilities	6,849.8	6,086.7
Commitments and contingencies (note 16)		
Stockholders' equity		
Common stockholders' equity	1,047.4	1,035.3
Retained earnings	1,772.4	1,574.8
Accumulated other comprehensive loss, net of tax	(49.1)	(40.6)
Treasury stock, at cost	(3.5)	(6.2)
Total OGE Energy stockholders' equity	2,767.2	2,563.3
Noncontrolling interests	305.2	256.0
Total stockholders' equity	3,072.4	2,819.3
Total liabilities and stockholders' equity	\$9,922.2	\$8,906.0

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

## CONSOLIDATED STATEMENTS OF CAPITALIZATION

(In millions, December 31)

	2012	2011
<b>Stockholders' equity</b>		
Common stock, par value \$0.01 per share; authorized 225.0 shares; and outstanding 98.8 and 98.1 shares, respectively	\$ 1.0	\$ 1.0
Premium on common stock	1,046.4	1,034.3
Retained earnings	1,772.4	1,574.8
Accumulated other comprehensive loss, net of tax	(49.1)	(40.6)
Treasury stock, at cost. 0.1 and 0.1 shares, respectively	(3.5)	(6.2)
Total OGE Energy stockholders' equity	2,767.2	2,563.3
Noncontrolling interest	305.2	256.0
Total stockholders' equity	3,072.4	2,819.3
<b>Long-term debt</b>		
Senior Notes – OGE Energy		
5.00% Senior Notes, Series Due November 15, 2014	100.0	100.0
Unamortized discount	(0.1)	(0.2)
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	250.0
3.70% Tinker Debt, Due August 31, 2062	10.7	–
Other Bonds – OG&E		
0.22% – 0.40% Garfield Industrial Authority, January 1, 2025	47.0	47.0
0.21% – 0.41% Muskogee Industrial Authority, January 1, 2025	32.4	32.4
0.20% – 0.47% Muskogee Industrial Authority, June 1, 2027	56.0	56.0
Unamortized discount	(5.8)	(6.2)
Enogex		
6.875% Senior Notes, Series Due July 15, 2014	200.0	200.0
1.72% Enogex LLC Term Loan Agreement, Due August 2, 2015	250.0	–
–% Enogex LLC Revolving Credit Agreement, Due December 13, 2016	–	150.0
6.25% Senior Notes, Series Due March 15, 2020	250.0	250.0
Unamortized discount	(1.6)	(1.9)
Total long-term debt	2,848.6	2,737.1
Total Capitalization	\$5,921.0	\$5,556.4

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
<b>Balance at December 31, 2009</b>	<b>\$1.0</b>	<b>\$ 886.7</b>	<b>\$1,227.8</b>	<b>\$(74.7)</b>	<b>\$ 20.0</b>	-	<b>\$2,060.8</b>
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
Distributions to noncontrolling interest partner	-	-	-	-	(4.0)	-	(4.0)
Deferred income taxes attributable to contributions from noncontrolling interest partner	-	(34.0)	-	-	-	-	(34.0)
<b>Balance at December 31, 2010</b>	<b>\$1.0</b>	<b>\$ 968.2</b>	<b>\$1,380.6</b>	<b>\$(60.2)</b>	<b>\$110.4</b>	-	<b>\$2,400.0</b>
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)
<b>Balance at December 31, 2011</b>	<b>\$1.0</b>	<b>\$1,034.3</b>	<b>\$1,574.8</b>	<b>\$(40.6)</b>	<b>\$256.0</b>	<b>\$(6.2)</b>	<b>\$2,819.3</b>
Comprehensive income (loss)							
Net income	-	-	355.0	-	30.0	-	385.0
Other comprehensive income (loss), net of tax	-	-	-	(8.5)	(3.5)	-	(12.0)
Comprehensive income (loss)	-	-	355.0	(8.5)	26.5	-	373.0
Dividends declared on common stock	-	-	(157.4)	-	-	-	(157.4)
Issuance of common stock	-	14.3	-	-	-	-	14.3
Stock-based compensation and other	-	(8.7)	-	-	(0.2)	6.1	(2.8)
Contributions from noncontrolling interest partners	-	10.7	-	-	35.5	-	46.2
Distributions to noncontrolling interest partners	-	-	-	-	(12.6)	-	(12.6)
Deferred income taxes attributable to contributions from noncontrolling interest partners	-	(4.2)	-	-	-	-	(4.2)
Purchase of treasury stock	-	-	-	-	-	(3.4)	(3.4)
<b>Balance at December 31, 2012</b>	<b>\$1.0</b>	<b>\$1,046.4</b>	<b>\$1,772.4</b>	<b>\$(49.1)</b>	<b>\$305.2</b>	<b>\$(3.5)</b>	<b>\$3,072.4</b>

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

## NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

### 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 three business segments: (i) electric utility, (ii) natural gas transportation and storage and (iii) natural gas gathering and processing. 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 and storing 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. During the third quarter of 2012, the operations and activities of EER were fully integrated with those of Enogex through the creation of a new commodity management organization. This new organization is intended to facilitate the execution of Enogex's strategy through an enhanced focus on asset optimization and active management of its growing natural gas, NGLs and condensate positions. The operations of EER, including asset management activities, have been included in the natural gas transportation and storage segment and have been restated for all prior periods presented. Enogex's operations are now organized into two business segments: (i) natural gas transportation and storage and (ii) natural gas gathering and processing. At December 31, 2012, OGE Energy indirectly owns a 79.9 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 consolidates 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, 2012 and 2011 and the results of its operations and cash flows for the years ended December 31, 2012, 2011 and 2010, 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)	2012	2011
<b>Regulatory assets</b>		
Current		
Crossroads wind farm rider under recovery <sup>(A)</sup>	\$ 14.9	\$ 2.5
Oklahoma demand program rider under recovery <sup>(A)</sup>	9.2	8.1
Fuel clause under recoveries	-	1.8
Other <sup>(A)</sup>	2.9	3.6
<b>Total current regulatory assets</b>	<b>\$ 27.0</b>	<b>\$ 16.0</b>
Non-current		
Benefit obligations regulatory asset	\$370.6	\$359.2
Income taxes recoverable from customers, net	54.7	54.0
Smart Grid	42.8	37.2
Unamortized loss on reacquired debt	13.0	14.2
Deferred storm expenses	12.7	23.8
Deferred pension expenses	4.5	9.1
Other	12.3	10.4
<b>Total non-current regulatory assets</b>	<b>\$510.6</b>	<b>\$507.9</b>
<b>Regulatory Liabilities</b>		
Current		
Fuel clause over recoveries	\$109.2	\$ 7.7
Smart Grid rider over recovery <sup>(B)</sup>	24.1	24.3
Other <sup>(B)</sup>	7.8	13.7
<b>Total current regulatory liabilities</b>	<b>\$141.1</b>	<b>\$ 45.7</b>
Non-Current		
Accrued removal obligations, net	\$218.2	\$208.2
Deferred pension credits	17.7	-
Pension tracker	9.2	22.5
<b>Total non-current regulatory liabilities</b>	<b>\$245.1</b>	<b>\$230.7</b>

<sup>(A)</sup> Included in Other Current Assets on the Consolidated Balance Sheets.

<sup>(B)</sup> Included in Other Current Liabilities on the Consolidated Balance Sheets.

OG&E recovers a return on the capital expenditures along with operation and maintenance expense and depreciation expense related to the Crossroads wind farm through a rider established by the OCC. OG&E began recovery in the fourth quarter of 2011 and believes the rider will continue until new rates are implemented in OG&E's next general rate case.

OG&E recovers program costs related to the Demand and Energy Efficiency Program. An extension of the demand program rider was approved in December 2012, which allows for the recovery of demand program costs, lost revenues associated with any achieved energy, demand savings and performance based incentives and the recovery of costs associated with research and development investments through December 2015.

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)	2012	2011
<b>Pension plan and restoration of retirement income plan:</b>		
Net loss	<b>\$278.6</b>	\$266.3
Prior service cost	<b>4.5</b>	7.0
<b>Postretirement plans:</b>		
Net loss	<b>134.6</b>	144.2
Prior service cost	<b>(47.1)</b>	(60.8)
Net transition obligation	-	2.5
<b>Total</b>	<b>\$370.6</b>	<b>\$359.2</b>

The following amounts in the benefit obligations regulatory asset at December 31, 2012 are expected to be recognized as components of net periodic benefit cost in 2013:

(In millions)	
<b>Pension plan and restoration of retirement income plan:</b>	
Net loss	\$ 19.8
Prior service cost	2.0
<b>Postretirement plans:</b>	
Net loss	18.1
Prior service cost	(13.7)
<b>Total</b>	<b>\$ 26.2</b>

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.

OG&E recovers 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 were 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 in OG&E's next general rate case. This project was completed in late 2012 and the smart grid project costs did not exceed \$366.4 million. 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 in OG&E's next general rate case. The stranded costs associated with OG&E's existing meters, which have been replaced by smart meters, were accumulated during the smart grid deployment and recovery of the stranded costs will be included in future rate cases. OG&E began recovering the 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 beginning with the first billing cycle in January 2013 through December 2013.

OG&E defers the Oklahoma storm-related operation and maintenance expenses in excess of \$2.7 million and reserves 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 2017.

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.

OG&E recovers specific amounts of pension and postretirement medical costs in rates approved in its Oklahoma rate cases. In accordance with approved orders, OG&E defers the difference between actual pension and postretirement medical expenses and the amount approved in its last Oklahoma rate case as a regulatory asset or regulatory liability. These amounts have been recorded in Pension tracker regulatory liability in the regulatory assets and liabilities table above.

In July 2009, OG&E was allowed to recover previously deferred pension costs over a four-year period ending in August 2013. OG&E also recovers its 2006 and 2007 pension settlement costs in Arkansas, which are being amortized over a 10-year period ending in January 2020. Both the Oklahoma and Arkansas pension plan expenses are reflected in Deferred Pension expenses asset in the regulatory assets and liabilities table above.

In September 2011, OG&E was allowed to include postretirement medical expenses in its pension tracker. In August 2012, OG&E was allowed to recover pension and postretirement medical expenses over a two-year period ending July 2014 which is included in Deferred Pension credits 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 OG&E 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 determination of Pension Plan assumptions, impairment estimates of long-lived assets (including intangible assets), 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 segment and the natural gas gathering and processing segment, 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, amortization methodologies related to intangible assets and impairment assessments of goodwill.

#### **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. Also, a portion of the uncollectible provision related to fuel is being recovered through the fuel adjustment clause. 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 \$2.6 million and \$3.8 million at December 31, 2012 and 2011, 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 \$76.8 million and \$76.9 million at December 31, 2012 and 2011, respectively.

##### Enogex

Natural gas inventory is held by Enogex, through its transportation and storage business, to provide operational support for its pipeline deliveries and 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 asset management activity, Enogex injects and withdraws natural gas into and out of inventory under the terms of its storage capacity contracts. During the years ended December 31, 2012, 2011 and 2010, Enogex recorded write-downs to market value related to natural gas storage inventory of \$5.5 million, \$4.8 million and \$0.3 million, respectively. The amount of Enogex's natural gas inventory was \$16.5 million and \$23.7 million at December 31, 2012 and 2011, 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

##### OG&E

Gas imbalances occur when the actual amounts of natural gas delivered from or received by OG&E differ from the amounts scheduled to be delivered or received. OG&E values all imbalances at an average of current market indices applicable to OG&E's operations, not to exceed net realizable value.

##### Enogex

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
<b>2012</b>				
McClain Plant	77%	\$182.1	\$56.3	\$125.8
Redbud Plant <sup>(A)</sup>	51%	\$458.5	\$69.5	\$389.0

<sup>(A)</sup> This amount includes a plant acquisition adjustment of \$148.3 million and accumulated amortization of \$23.3 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.

## 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 MMcf/d of the total 180 MMcf/d of capacity, at that facility. 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. 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. In March 2012, Enogex reached a settlement agreement with its insurers in this matter. As a result of the settlement agreement, Enogex received additional reimbursements of \$7.6 million and recognized a gain of \$7.5 million on insurance proceeds in 2012.

In a period in which the Company has an event that results in the recognition of a material gain or loss on an event that is covered by insurance proceeds, the Company records an impairment loss for the book value of the damaged asset and an offsetting gain for insurance proceeds if recovery of the loss is considered probable. To the extent proceeds from an insurance settlement exceed recognized losses, the Company records a gain on insurance proceeds in earnings as the receipts of proceeds are determined to be probable.

## 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
<b>2012</b>			
OGE Energy (holding company)			
Property, plant and equipment	\$ 142.1	\$ 103.2	\$ 38.9
OGE Energy property, plant and equipment	142.1	103.2	38.9
OG&E			
Distribution assets	3,222.7	969.6	2,253.1
Electric generation assets <sup>(A)</sup>	3,446.6	1,242.4	2,204.2
Transmission assets <sup>(B)</sup>	1,712.6	359.8	1,352.8
Intangible plant	50.2	25.0	25.2
Other property and equipment	317.6	108.8	208.8
OG&E property, plant and equipment	8,749.7	2,705.6	6,044.1
Enogex			
Natural gas transportation and storage assets	988.6	292.7	695.9
Natural gas gathering and processing assets	2,011.5	445.6	1,565.9
Enogex property, plant and equipment	3,000.1	738.3	2,261.8
Total property, plant and equipment	\$11,891.9	\$3,547.1	\$8,344.8

<sup>(A)</sup> This amount includes a plant acquisition adjustment of \$148.3 million and accumulated amortization of \$23.3 million.

<sup>(B)</sup> This amount includes a plant acquisition adjustment of \$3.3 million and accumulated amortization of \$0.3 million.

(In millions, December 31)	Total Property, Plant and Equipment	Accumulated Depreciation	Net Property, Plant and Equipment
<b>2011</b>			
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 <sup>(A)</sup>	3,360.6	1,215.8	2,144.8
Transmission assets <sup>(B)</sup>	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			
Natural gas transportation and storage assets	967.0	277.0	690.0
Natural gas gathering and processing assets	1,580.1	381.0	1,199.1
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

<sup>(A)</sup> This amount includes a plant acquisition adjustment of \$148.3 million and accumulated amortization of \$17.9 million.

<sup>(B)</sup> This amount includes a plant acquisition adjustment of \$3.3 million and accumulated amortization of \$0.2 million.

The following table summarizes the Company's unamortized computer software costs.

(In millions, December 31)	2012	2011
OGE Energy (holding company)	\$11.6	\$14.0
OG&E	17.6	6.7
Enogex	3.9	4.4
Total	\$33.1	\$25.1

The following table summarized the Company's amortization expense for computer software costs.

(In millions, year ended December 31)	2012	2011	2010
OGE Energy (holding company)	\$ 6.8	\$6.4	\$ 5.3
OG&E	4.2	1.8	2.6
Enogex	3.1	1.0	2.2
Total	\$14.1	\$9.2	\$10.1

## Intangible Assets

Enogex

The following table below summarizes Enogex's intangible assets and related accumulated amortization at:

(In millions)	Total Intangible Assets	Accumulated Amortization	Net Intangible Assets
December 31, 2012			
Customer contract/acreage dedication	\$141.9	\$14.5	\$127.4
December 31, 2011			
Customer contract/acreage dedication	\$141.9	\$ 4.9	\$137.0

In 2012, 2011 and 2010, amortization expense for intangible assets was \$9.6 million, \$2.1 million and \$0.6 million, respectively, including amortization of certain customer-based intangible assets associated with the acquisition from Cordillera in November 2011, which is included in gross margin for financial reporting purposes.

The following table summarizes Enogex's expected amortization of intangible assets for each of the next five years.

(In millions)	2013	2014	2015	2016	2017
Expected amortization of intangible assets	\$9.5	\$9.5	\$9.5	\$9.5	\$9.1

## Depreciation and Amortization

### OG&E

The provision for depreciation, which was 3.0 percent and 2.9 percent, respectively, of the average depreciable utility plant for 2012 and 2011, 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. Amortization of intangible assets is computed using the straight-line method. Of the remaining amortizable intangible plant balance at December 31, 2012, 92.4 percent will be amortized over 9.25 years with 7.6 percent of the remaining amortizable intangible plant balance at December 31, 2012 being amortized over their respective lives ranging from three to five 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 sub-station 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 15 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. Intangible assets are amortized on a straight-line basis over their useful lives 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 three months to 74 years. The Company also has certain asset retirement obligations primarily related to Enogex's processing plants and compression sites that have not been recorded because the Company cannot determine when these obligations will be incurred.

The following table summarizes changes to the Company's asset retirement obligations during the years ended December 31, 2012 and 2011.

(In millions)	2012	2011
Balance at January 1	\$24.8	\$11.1
Liabilities incurred <sup>(A)</sup>	0.4	13.0
Accretion expense	1.9	0.7
Revisions in estimated cash flows <sup>(B)</sup>	26.9	–
Balance at December 31	\$54.0	\$24.8

<sup>(A)</sup> Due to certain Enogex compression assets in 2012 and OG&E's Crossroads wind farm in 2011.

<sup>(B)</sup> Due to changes to OG&E's asset retirement obligations related to its wind farms due to a change in the assumption related to the timing of removal used in the valuation of the asset retirement obligations.

## Assessing 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 2012, 2011 or 2010.

As a result of the gas gathering acquisitions in November 2011, Enogex recorded goodwill of \$39.4 million. Enogex assesses its goodwill for impairment at least annually as of October 1 by comparing the fair value of the reporting unit with its book value, including goodwill. Enogex utilizes the income approach (generally accepted valuation approach) to estimate the fair value of the reporting unit, also giving consideration to alternative methods such as the market and cost approaches. Under the income approach, anticipated cash flows over a period of years plus a terminal value are discounted to present value using appropriate discount rates. Enogex performs its goodwill impairment testing at the natural gas gathering and processing segment reporting unit level. Enogex recorded no impairments of goodwill in 2012.

### 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 an increase to net other income and 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 8.93 percent, 8.71 percent and 8.89 percent for the years ended December 31, 2012, 2011 and 2010, respectively. The increase in the allowance for funds used during construction rates in 2012 was primarily due to an increase in commercial paper fees in 2012 which resulted in an increase in the cost of short-term debt borrowings.

### Collection of Sales Tax

In the normal 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 and storage 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 2012 included Chesapeake Energy Marketing Inc., Apache Corporation and Devon Energy Production Company, L.P. In 2012, these customers accounted for 19.6 percent, 17.8 percent and 10.6 percent, respectively, of Enogex's gathering and processing volumes. In 2012, Enogex's top 10 natural gas producer customers accounted for 73.0 percent of Enogex's gathering and processing volumes.

Enogex recognizes revenue from natural gas gathering, processing, transportation and storage 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 third parties at the inlet of their facilities. Additionally, one third party purchases 50 percent of the NGLs delivered to its system, which accounted for \$297.3 million (43.3 percent), \$285.4 million (38.8 percent) and \$279.8 million (46.0 percent), respectively, of Enogex's total NGLs sales for the years ended December 31, 2012, 2011 and 2010.

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 natural gas gathering and processing volumes on the Oklahoma portion of Enogex's system. As a result, Enogex has recorded \$7.1 million in Deferred Revenues on the Company's Consolidated Balance Sheet at December 31, 2012, which are expected to be recognized based on the estimated average fee per MMBtu processed by the end of 2014. Enogex has also recorded \$1.5 million in Deferred Revenues on the Company's Consolidated Balance Sheet at December 31, 2012 in connection with other gathering and processing agreements.



Enogex engages in asset management and hedging activities related to the purchase and sale of natural gas and NGLs. Contracts utilized in these activities generally include purchases and sales for physical delivery, over-the-counter forward swap and options contracts and exchange traded futures and options. Enogex'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 purchase and 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 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.

#### 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, 2012 and 2011 attributable to OGE Energy. At both December 31, 2012 and 2011, there was no accumulated other comprehensive loss related to Enogex's noncontrolling interest in Atoka.

(In millions, December 31)	2012	2011
<b>Pension plan and restoration of retirement income plan:</b>		
Net loss	\$(49.3)	\$(42.1)
Prior service cost	0.1	(0.1)
<b>Postretirement plans:</b>		
Net loss	(15.7)	(15.4)
Prior service cost	7.2	9.0
Net transition obligation	-	(0.1)
<b>Deferred commodity contracts hedging gains</b>	<b>0.1</b>	<b>3.3</b>
<b>Deferred interest rate swap hedging losses</b>	<b>(0.5)</b>	<b>(0.7)</b>
Total accumulated other comprehensive loss	<b>(58.1)</b>	<b>(46.1)</b>
Less: Accumulated other comprehensive loss attributable to noncontrolling interests	<b>(9.0)</b>	<b>(5.5)</b>
Accumulated other comprehensive loss, net of tax	<b>\$(49.1)</b>	<b>\$(40.6)</b>

The amounts in accumulated other comprehensive loss at December 31, 2012 that are expected to be recognized into earnings in 2013 are as follows:

(In millions)	
<b>Pension plan and restoration of retirement income plan:</b>	
Net loss	\$ 3.3
Prior service cost	0.1
<b>Postretirement plans:</b>	
Net loss	2.0
Prior service cost	(1.8)
<b>Deferred commodity contracts hedging gains</b>	<b>0.1</b>
<b>Deferred interest rate swap hedging losses</b>	<b>(0.2)</b>
Total, net of tax	<b>\$ 3.5</b>

### **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 had \$5.8 million and \$5.5 million in accrued environmental liabilities at December 31, 2012 and 2011, respectively, which are included in the summary of asset retirement obligations above.

### **Reclassifications**

As discussed in Note 15, during the third quarter of 2012, the operations and activities of EER were fully integrated with those of Enogex through the creation of a new commodity management organization. The operations of EER, including asset management activities, have been included in the natural gas transportation and storage segment and have been restated for all prior periods presented to conform to the 2012 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. On January 31, 2013, the Financial Accounting Standards Board issued an update to this standard clarifying that the scope includes derivatives, including bifurcated embedded derivatives, repurchase agreements and reverse repurchase agreements, and securities borrowing and securities lending transactions that are either offset or are subject to a master netting arrangement or similar agreement.

The new standard is effective for interim and annual reporting periods for fiscal years beginning on or after January 1, 2013 and is required to be applied retrospectively for all periods presented. The Company adopted this new standard effective January 1, 2013 and will provide any additional disclosures necessary to comply with the new standard in its Form 10-Q for the quarter ended March 31, 2013.

In February 2013, the Financial Accounting Standards Board issued "Comprehensive Income: Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Income." The new standard requires an entity to provide information about the amounts reclassified out of accumulated other comprehensive income by component. In addition, the new standard requires an entity to present, either on the face of the statement where net income is presented or in the notes, significant amounts reclassified out of accumulated other comprehensive income by the respective line items in net income but only if the amount reclassified is required under GAAP to be reclassified to net income in its entirety in the same reporting period. For other amounts that are not required under GAAP to be reclassified in their entirety to net income, an entity is required to cross-reference to other disclosures required under GAAP that provide additional detail about those amounts. The new standard is applicable for all entities that issue financial statements that are presented in conformity with GAAP and that report items of other comprehensive income. The new standard is effective for interim and annual reporting periods for fiscal years beginning after December 15, 2012 and is required to be applied prospectively. The Company adopted this new standard effective January 1, 2013 and will provide any additional disclosures necessary to comply with the new standard in its Form 10-Q for the quarter ended March 31, 2013.

### **3. Gas Gathering and Processing Acquisitions and Divestitures**

#### **Western Oklahoma Gathering Acquisition**

On September 23, 2011, Enogex entered into the following agreements: an agreement with 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 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 following table summarizes the 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)
<b>Total</b>	<b>\$200.4</b>

The goodwill recognized from this acquisition primarily related to the benefits associated with combining the acquired assets with Enogex's existing assets and operations. All of the goodwill is deductible for tax purposes. The transactions have provided Enogex with key new opportunities in the Granite Wash area. The goodwill has been recorded in the natural gas gathering and processing segment. At December 31, 2012 and 2011, there were no changes in the recognized amount of goodwill resulting from this acquisition, as discussed in Note 1.

Intangible assets consist of identifiable customer contracts and relationships. The acquired intangible assets are being amortized on a straight-line basis over the estimated useful life of 15 years. The net amount of intangible assets and related accumulated amortization was \$125.7 million and \$10.6 million at December 31, 2012 and \$134.8 million and \$1.5 million at December 31, 2011, respectively.

#### Granite Wash Gathering Acquisition

On August 1, 2012, Enogex entered into agreements with Chesapeake Midstream Gas Services, L.L.C. and Mid-America Midstream Gas Services, L.L.C., wholly-owned subsidiaries of Access Midstream Partners, L.P. and Chesapeake Midstream Development, L.P., respectively, pursuant to which Enogex agreed to acquire approximately 235 miles of natural gas gathering pipelines, right-of-ways and certain other midstream assets that provide natural gas gathering services in the greater Granite Wash area. The transactions closed on August 31, 2012. The aggregate purchase price for these transactions was approximately \$78.6 million including reimbursement for certain permitted capital expenditures incurred during the period beginning June 1, 2012 and ending August 31, 2012. Enogex utilized cash generated from operations and bank borrowings to fund the purchase. In addition, Enogex also incurred acquisition-related costs of \$3.5 million for sales taxes on acquired assets, which are included in taxes other than income.

The acquisition described above was accounted for as a business combination. The purchase price is preliminary and has been allocated to property, plant and equipment based on the estimated fair values at the acquisition date using a third-party valuation expert. This allocation 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 becomes available. Enogex expects the purchase price allocations to be completed by the end of the first quarter of 2013.

In connection with these agreements, Enogex entered into a gas gathering and processing agreement with Chesapeake effective September 1, 2012 pursuant to which Enogex began providing fee-based natural gas gathering, compression, processing and transportation services to Chesapeake with respect to certain acreage dedicated by Chesapeake.

#### Texas Panhandle Gathering Divestiture

On January 2, 2013, Enogex and one of its five largest customers entered into new agreements, effective January 1, 2013, relating to the customer's gathering and processing volumes on the Texas portion of Enogex's system. The effects of this new arrangement are (i) a fixed fee processing agreement replaces the previous keep-whole agreement, (ii) the acreage dedicated by the customer to Enogex for gathering and processing in Texas has been increased for an extended term and (iii) the sale by Enogex of certain gas gathering assets in the Texas Panhandle portion of Enogex's system to this customer for cash proceeds of approximately \$35 million. The sale of these assets was approved by the Company's and Enogex's Board of Directors in November 2012, therefore these assets were classified as held for sale on the Company's Consolidated Balance Sheet at December 31, 2012. Enogex expects to recognize a pre-tax gain of approximately \$10 million in the first quarter of 2013 in its natural gas gathering and processing segment from the sale of these assets.

#### Harrah Gathering and Processing Divestiture

On April 1, 2011, Enogex completed the sale of its Harrah processing plant (38 MMcf/d of capacity) and the associated Wellston and Davenport gathering assets. The proceeds from the sale were \$15.9 million and Enogex recorded a pre-tax gain in the second quarter of 2011 of \$3.7 million in its natural gas gathering and processing segment.

#### 4. Noncontrolling Interests

The following table summarizes changes in OGE Holdings' and the ArcLight group's membership interest in Enogex Holdings in 2012.

(In millions)	OGE Holdings	ArcLight Group	Total
Balance at December 31, 2011 (units)	93.8	21.6	115.4
Ownership percentage at			
December 31, 2011	81.3%	18.7%	100.0%
Issuance of 5,294,118 units of Enogex Holdings <sup>(A)</sup>	2.7	2.6	5.3
Balance at December 31, 2012 (units)	96.5	24.2	120.7
Ownership percentage at			
December 31, 2012	79.9%	20.1%	100.0%

<sup>(A)</sup> Effective October 1, 2012, OGE Energy and the ArcLight group made contributions to Enogex Holdings of \$45.0 million each to fund a portion of Enogex LLC's 2012 capital requirements.

The following table summarizes changes in OGE Energy's equity which represents changes in additional paid-in capital for unrecognized gains from the issuance of equity interests in Enogex Holdings to the ArcLight group in 2012.

(In millions)	
Net income attributable to OGE Energy	\$355.0
Transfers from the noncontrolling interest	
Increase in paid-in capital for issuance of 5,294,118 units of Enogex Holdings (net of tax of \$3.2 million)	5.1
Net transfers from the noncontrolling interest	5.1
Total of net income attributable to OGE Energy and transfers from noncontrolling interest	\$360.1

Pursuant to the Enogex Holdings LLC Agreement, Enogex Holdings makes quarterly distributions to its partners. The following table summarizes the quarterly distributions in 2012.

(In millions)	OGE Holdings' Portion	ArcLight Group's Portion	Total Distribution
First quarter 2012	\$24.4	\$ 5.6	\$30.0
Second quarter 2012	10.1	2.4	12.5
Third quarter 2012	10.2	2.3	12.5
Fourth quarter 2012	10.2	2.3	12.5
Total	\$54.9	\$12.6	\$67.5

During 2012, Atoka's noncontrolling interest partner made contributions of \$1.2 million to Atoka. Enogex LLC made no distributions during 2012 to its Atoka partner, as there is no minimum distribution requirement related to Atoka.

## 5. Impairment of Assets

Atoka previously 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 natural gas gathering and processing segment associated with the cost it had capitalized in connection with the installation of the lease plant as it will not be able to recover the remaining value of the assets through future cash flows. The noncontrolling interest portion of the pre-tax impairment loss was \$2.5 million which was 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 options 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).

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, 2012 and 2011 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, 2012 and 2011. There were no Level 3 investments held at December 31, 2012 or 2011.

(In millions, December 31)	Commodity Contracts		Gas Imbalances <sup>(A)</sup>	
	Assets	Liabilities	Assets <sup>(B)</sup>	Liabilities <sup>(C)</sup>
<b>2012</b>				
Quoted market prices in active market for identical assets (Level 1)	\$ 5.0	\$ 5.0	\$ -	\$ -
Significant other observable inputs (Level 2)	0.5	0.5	3.1	3.8
Total fair value	5.5	5.5	3.1	3.8
Netting adjustments	(5.0)	(5.2)	-	-
Total	\$ 0.5	\$ 0.3	\$3.1	\$3.8
<b>2011</b>				
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

<sup>(A)</sup> 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.

<sup>(B)</sup> Gas imbalance assets exclude fuel reserves for under retained fuel due from shippers of \$5.9 million at December 31, 2012 with no comparable item at December 31, 2011, 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.

<sup>(C)</sup> Gas imbalance liabilities exclude fuel reserves for over retained fuel due to shippers of \$1.2 million and \$2.0 million at December 31, 2012 and 2011, 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 that are measured at fair value on a recurring basis using significant unobservable inputs (Level 3) during 2011. There were no Level 3 investments held at December 31, 2012 or 2011.

(In millions)	Commodity Contracts Assets
<b>2011</b>	
Balance at January 1	\$13.3
Total gains or losses included in other comprehensive income	(5.4)
Settlements	(7.9)
Balance at December 31	\$ -

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:

(In millions, December 31)	2012		2011	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
<b>PRM assets</b>				
Energy derivative contracts	\$ 0.5	\$ 0.5	\$ 3.8	\$ 3.8
<b>PRM liabilities</b>				
Energy derivative contracts	\$ 0.3	\$ 0.3	\$ 0.5	\$ 0.5
<b>Long-term debt</b>				
OG&E senior notes	\$1,904.2	\$2,401.6	\$1,903.8	\$2,383.8
OG&E industrial authority bonds	135.4	135.4	135.4	135.4
OG&E tinker debt <sup>(A)</sup>	10.7	10.0	-	-
OGE Energy senior notes	99.9	106.3	99.8	108.5
Enogex LLC senior notes	448.4	493.4	448.1	497.9
Enogex LLC revolving credit agreement	-	-	150.0	150.0
Enogex LLC term loan	250.0	250.0	-	-

<sup>(A)</sup> In September 2012, OG&E purchased the electric distribution system at Tinker Air Force Base for \$10.7 million and began making installment payments over a 50-year term. The fair value of this debt was based on calculating the net present value of the monthly payments discounted by the Company's current borrowing rate. Since the debt was valued using unobservable inputs, it was classified as Level 3 in the fair value hierarchy. This was a non-cash investing and financing activity as discussed in Note 9.

The carrying value of the financial instruments included in the Consolidated Balance Sheets 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 and is classified as Level 2 in the fair value hierarchy.

## 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 has used forward physical contracts, commodity price swap contracts and commodity price option features to manage the Company's commodity price risk exposures in the past. 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; and
- Natural gas futures and swaps, natural gas options and natural gas commodity purchases and sales are used to manage Enogex's natural gas exposure associated with its storage and transportation contracts and asset management 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 purchase and 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 (Loss) 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 operations and natural gas transportation 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, 2012 mature by the end of the first quarter of 2013.

### 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, 2012 and 2011, 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 Enogex's asset management 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, 2012, the Company had the following derivative instruments that were designated as cash flow hedges.

(In millions)	2012
<b>Gross Notional Volume<sup>(A)</sup></b>	
Enogex hedges	
Natural gas sales	3.7

<sup>(A)</sup> Natural gas in MMBtu's.

At December 31, 2012, the Company had the following derivative instruments that were not designated as hedging instruments.

(In millions)	Purchases	Sales
<b>Gross Notional Volume<sup>(A)</sup></b>		
Natural gas <sup>(B)</sup>		
Physical <sup>(C)(D)</sup>	7.0	30.1
Fixed swaps/futures	16.2	17.9
Basis swaps	7.3	6.7

<sup>(A)</sup> Natural gas in MMBtu's.

<sup>(B)</sup> 95.1 percent of the natural gas contracts have durations of one year or less, 2.9 percent have durations of more than one year and less than two years and 2.0 percent have durations of more than two years.

<sup>(C)</sup> 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.

<sup>(D)</sup> 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, 2012 are as follows:

(In millions) Instrument	Balance Sheet Location	Fair Value	
		Assets	Liabilities
<b>Derivatives designated as hedging instruments</b>			
Natural gas			
Financial futures/swaps	Other Current Assets	\$ -	\$0.5
Total		\$ -	\$0.5
<b>Derivatives not designated as hedging instruments</b>			
Natural gas			
Financial futures/swaps	Current PRM	\$0.1	\$ -
	Other Current Assets	5.0	4.7
Physical purchases/sales	Current PRM	0.4	0.3
Total		\$5.5	\$5.0
Total gross derivatives <sup>(A)</sup>		\$5.5	\$5.5

<sup>(A)</sup> See Note 6 for a reconciliation of the Company's total derivatives fair value to the Company's Consolidated Balance Sheet at December 31, 2012.

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

(In millions) Instrument	Balance Sheet Location	Fair Value	
		Assets	Liabilities
<b>Derivatives designated as hedging instruments</b>			
Natural gas			
Financial futures/swaps	Other Current Assets	\$ 5.2	\$ 0.3
Total		\$ 5.2	\$ 0.3
<b>Derivatives not designated as hedging instruments</b>			
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 <sup>(A)</sup>		\$61.3	\$53.5

<sup>(A)</sup> 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.

### 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 2012.

(In millions)	Amount Recognized in Other Comprehensive Income <sup>(A)</sup>	Amount Accumulated from Other Comprehensive Income (Loss) into Income	Amount Recognized in Income
<b>Derivatives in cash flow hedging relationships</b>			
Natural gas financial futures/swaps	\$0.5	\$ 5.2	\$ -
Interest rate swap	-	(0.4)	-
Total	\$0.5	\$ 4.8	\$ -

<sup>(A)</sup> The estimated net amount of gains or losses included in Accumulated Other Comprehensive Income (Loss) at December 31, 2012 that is expected to be reclassified into income within the next 12 months is a loss of \$0.2 million.

(In millions)	Amount Recognized in Income
<b>Derivatives not designated as hedging instruments</b>	
Natural gas physical purchases/sales	\$(11.7)
Natural gas financial futures/swaps	1.1
Total	\$(10.6)

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	Amount Reclassified from Accumulated Other Comprehensive Income (Loss) into Income	Amount Recognized in Income
<b>Derivatives in cash flow hedging relationships</b>			
NGLs financial options	\$(8.4)	\$ (9.8)	\$ -
Natural gas financial futures/swaps	2.9	(30.4)	-
Interest rate swap	-	(0.4)	-
<b>Total</b>	<b>\$(5.5)</b>	<b>\$(40.6)</b>	<b>\$ -</b>

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

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 (Loss) into Income	Amount Recognized in Income
<b>Derivatives in cash flow hedging relationships</b>			
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
Interest rate swap	-	(0.4)	-
<b>Total</b>	<b>\$(22.9)</b>	<b>\$(28.8)</b>	<b>\$0.2</b>

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

For derivatives designated as cash flow hedges in the tables above, amounts reclassified from Accumulated Other Comprehensive Income (Loss) into income (effective portion) and amounts recognized in income (ineffective portion) for the years ended December 31, 2012, 2011 and 2010, 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, 2012, 2011 and 2010, 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, 2012, the Company would have been required to post \$0.2 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, 2012. 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, 2012, 2011 and 2010 related to the Company's performance units and restricted stock.

(In millions, year ended December 31)	2012	2011	2010
<b>Performance units</b>			
Total shareholder return	\$ 8.0	\$ 8.2	\$ 6.8
Earnings per share	4.2	5.5	2.5
Total performance units	12.2	13.7	9.3
<b>Restricted stock</b>			
Total compensation expense	\$12.8	\$14.7	\$10.2
Income tax benefit	\$ 4.9	\$ 5.7	\$ 3.9

The Company has issued new shares to satisfy stock option exercises, restricted stock grants and payouts of earned performance units. In 2012, 2011 and 2010, there were 424,555 shares, 311,623 shares and 255,389 shares, respectively, of new common stock issued pursuant to the Company's stock incentive plans related to exercised stock options, restricted stock grants (net of forfeitures) and payouts of earned performance units. In 2012, there were 5,911 shares of restricted stock returned to the Company to satisfy tax liabilities.

In November 2012, the Company purchased 60,000 shares of its common stock at an average cost of \$55.41 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 2013. 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 these 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.

	2012	2011	2010
Number of units granted	<b>169,339</b>	213,721	214,750
Fair value of units granted	<b>\$ 51.82</b>	\$ 46.09	\$ 39.43
Expected dividend yield	<b>3.0%</b>	3.2%	3.9%
Expected price volatility	<b>22.0%</b>	33.0%	34.0%
Risk-free interest rate	<b>0.38%</b>	1.40%	1.42%
Expected life of units (in years)	<b>2.87</b>	2.87	2.87

### 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.

	2012	2011	2010
Number of units granted	<b>40,797</b>	71,238	71,585
Fair value of units granted	<b>\$ 47.63</b>	\$ 41.61	\$ 32.44

In 2012, the performance unit grant for Enogex employees that was previously based on earnings per share was changed to a cash payment that entitles Enogex employees to receive from 0 percent to 200 percent of the performance units granted based on the growth in Enogex's EBITDA over a three-year award cycle (i.e., three-year cliff vesting period) compared to a growth target set by the Compensation Committee of the Company's Board of Directors.

## 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.

	2012	2011	2010
Shares of restricted stock granted	5,412	17,902	26,653
Fair value of restricted stock granted	\$53.44	\$ 48.82	\$ 40.78

A summary of the activity for the Company's performance units and restricted stock at December 31, 2012 and changes in 2012 are shown in the following table.

	Performance Units					
	Total Shareholder Return		Earnings Per Share		Restricted Stock	
	Number of Units	Aggregate Intrinsic Value	Number of Units	Aggregate Intrinsic Value	Number of Shares	Aggregate Intrinsic Value
Units/shares outstanding at 12/31/11	706,124		235,376		37,244	
Granted <sup>(A)</sup>	169,339		40,797		5,412	
Converted <sup>(B)</sup>	(291,294)	\$30.6	(97,099)	\$10.2	N/A	
Vested	N/A		N/A		(15,847)	\$0.9
Forfeited	(49,605)		(15,155)		(2,256)	
Units/shares outstanding at 12/31/12	534,564	\$46.3	163,919	\$13.8	24,553	\$1.4
Units/shares fully vested at 12/31/12	188,633	\$21.2	62,880	\$ 7.1		

<sup>(A)</sup> For performance units, this represents the target number of performance units granted. Actual number of performance units earned, if any, is dependent upon performance and may range from 0 percent to 200 percent of the target.

<sup>(B)</sup> These amounts represent performance units that vested at December 31, 2011 which were settled in February 2012.

A summary of the activity for the Company's non-vested performance units and restricted stock at December 31, 2012 and changes in 2012 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 12/31/11	414,830	\$42.75	138,277	\$37.01	37,244	\$44.24
Granted	169,339 <sup>(A)</sup>	\$51.82	40,797 <sup>(A)</sup>	\$47.63	5,412	\$53.44
Vested	(188,633)	\$39.43	(62,880)	\$32.44	(15,847)	\$42.78
Forfeited	(49,605)	\$44.24	(15,155)	\$38.02	(2,256)	\$44.22
Units/shares non-vested at 12/31/12	345,931	\$48.79	101,039	\$44.00	24,553	\$47.21
Units/shares expected to vest	323,303		94,557		24,553	

<sup>(A)</sup> For performance units, this represents the target number of performance units granted. Actual number of performance 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)	2012	2011	2010
Performance units			
Total shareholder return	\$7.4	\$7.4	\$5.4
Earnings per share	4.1	3.9	1.9
Restricted stock	0.7	1.0	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)
<b>2012</b>		
Performance units		
Total shareholder return	\$ 7.7	1.64
Earnings per share	3.9	1.14
Total performance units	11.6	
Restricted stock	0.5	1.96
Total	\$12.1	

### 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, 2012 and changes during 2012 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 12/31/11	55,800	\$23.19		
Exercised	(36,200)	\$23.41	\$2.0	
Options outstanding at 12/31/12	19,600	\$22.80	\$0.6	0.95 years
Options fully vested and exercisable at 12/31/12	19,600	\$22.80	\$0.6	0.95 years

A summary of the activity for the Company's exercised stock options in 2012, 2011 and 2010 are shown in the following table.

(In millions, year ended December 31)	2012	2011	2010
Intrinsic value <sup>(A)</sup>	\$2.0	\$2.2	\$2.5
Cash received from stock options exercised	0.8	1.3	3.2
Income tax benefit realized for the tax deductions from exercised stock options <sup>(B)</sup>	-	-	1.0

<sup>(A)</sup> The difference between the market value on the date of exercise and the option exercise price.

<sup>(B)</sup> The Company did not realize an income tax benefit for the tax deductions from the exercised stock options in 2012 and 2011 due to the Company being in a tax net operating loss position in 2012 and 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)	2012	2011	2010
<b>Non-cash investing and financing activities</b>			
Installment payments for Tinker electric distribution system	\$ 10.6	\$ -	\$ -
Power plant long-term service agreement	-	1.7	2.7
Future installment payments to wind farm developer	-	-	2.3

### Supplemental cash flow information

Cash paid during the period for	2012	2011	2010
Interest (net of interest capitalized) <sup>(A)</sup>	\$161.3	\$138.9	\$ 144.6
Income taxes (net of income tax refunds)	(9.1)	4.7	(139.5)

<sup>(A)</sup> Net of interest capitalized of \$8.0 million, \$19.1 million and \$8.0 million in 2012, 2011 and 2010, respectively.

### 10. Income Taxes

The items comprising income tax expense are as follows:

(In millions, year ended December 31)	2012	2011	2010
<b>Provision (benefit) for current income taxes</b>			
Federal	\$ (9.1)	\$ (5.4)	\$ 12.8
State	0.5	0.1	1.8
Total provision (benefit) for current income taxes	(8.6)	(5.3)	14.6
<b>Provision for deferred income taxes, net</b>			
Federal	147.3	165.5	139.8
State	(1.5)	3.8	10.3
Total provision for deferred income taxes, net	145.8	169.3	150.1
Deferred federal investment tax credits, net	(2.1)	(3.3)	(3.7)
Total income tax expense	\$135.1	\$160.7	\$161.0

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 2009 or state and local tax examinations by tax authorities for years prior to 2005. 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 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)	2012	2011	2010
Statutory Federal tax rate	35.0%	35.0%	35.0%
Amortization of net unfunded deferred taxes	0.8	0.7	0.7
Medicare Part D subsidy	-	0.2	2.6
Qualified production activities	-	-	(0.2)
State income taxes, net of Federal income tax benefit	(0.1)	0.6	1.7
Federal investment tax credits, net	(0.4)	(0.7)	(0.8)
401(k) dividends	(0.5)	(0.5)	(0.6)
Income attributable to noncontrolling interest	(1.6)	(1.3)	(0.4)
Federal renewable energy credit <sup>(A)</sup>	(7.2)	(3.4)	(3.4)
Other	-	0.1	0.3
Effective income tax rate	26.0%	30.7%	34.9%

<sup>(A)</sup> These are credits associated with the production from OG&E's wind farms.

At December 31, 2012 and 2011, 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, 2012 and 2011, respectively, were as follows:

(in millions, December 31)	2012	2011
<b>Current deferred income tax assets</b>		
Net operating losses	\$ 152.4	\$ 15.8
Accrued liabilities	27.1	13.2
Federal tax credits	6.0	-
Accrued vacation	3.8	4.2
Uncollectible accounts	1.0	1.4
Total current deferred income tax assets	190.3	34.6
<b>Current accrued income tax liabilities</b>		
Derivative instruments	(2.6)	(2.5)
Total current accrued income tax liabilities	(2.6)	(2.5)
Current deferred income tax assets, net	\$ 187.7	\$ 32.1
<b>Non-current deferred income tax liabilities</b>		
Accelerated depreciation and other property related differences	\$1,660.3	\$1,437.5
Investment in Enogex Holdings	638.0	571.8
Company pension plan	52.4	67.5
Income taxes refundable to customers, net	21.2	28.0
Regulatory asset	18.8	21.2
Bond redemption-unamortized costs	4.0	4.4
Derivative instruments	1.5	-
Total non-current deferred income tax liabilities	2,396.2	2,130.4
<b>Non-current deferred income tax assets</b>		
Net operating losses	(159.1)	(225.2)
State tax credits	(83.7)	(63.0)
Regulatory liabilities	(71.4)	(65.3)
Federal tax credits	(69.6)	(49.7)
Postretirement medical and life insurance benefits	(57.6)	(50.2)
Derivative instruments	-	(12.1)
Deferred Federal investment tax credits	(1.5)	(2.3)
Other	(4.5)	(11.2)
Total non-current deferred income tax assets	(447.4)	(479.0)
Non-current deferred income tax liabilities, net	\$1,948.8	\$1,651.4

During 2012 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 allowed the Company to record a current income tax deduction for 100 percent of the cost of certain property placed into service in 2011 and 50 percent for certain property placed into service in 2012. For financial accounting purposes, the Company recorded an increase in its Non-Current Deferred Income Taxes Liability at December 31, 2012 and 2011 on the Company's Consolidated Balance Sheet to recognize the financial statement impact of this new law.

On January 2, 2013, the American Taxpayer Relief Act of 2012 was signed into law. Among other things, the law included an extension of bonus depreciation for one year for property generally placed in service before January 1, 2014. Because this new law was enacted in 2013, GAAP requires the law to be considered retroactive legislation, the impact of which must be recorded in the period enacted. The impact of the new law will be reflected in the Company's 2013 Consolidated Financial Statements as an increase in Deferred Tax Liabilities with a corresponding increase in Deferred Tax Assets related to the net operating loss.

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 could 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 were deferred and will be utilized at a future date. For financial accounting purposes, the Company is receiving the benefits as most of these credits did not expire if they were not utilized in the period they were generated.

#### Other

The Company sustained Federal and state tax operating losses in 2012 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 2012 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. Under current law, 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	\$1,026.8	\$ 37.8	2030
Federal operating loss	781.9	273.7	2030
Federal tax credits	75.6	75.6	2029
State tax credits			
Oklahoma investment tax credits	100.5	65.3	N/A
Oklahoma capital investment board credits	7.3	7.3	N/A
Oklahoma zero emission tax credits	16.2	11.1	2020

Under tax law in effect at December 31, 2012, the Company projected utilization of \$711.0 million of tax loss carry forward in 2013 and recorded a current deferred tax asset of \$152.4 million. The remaining \$159.1 million was recorded as a non-current deferred tax asset for utilization in periods after 2013. With the passage of the American Taxpayer Relief Act of 2012 on January 2, 2013, the Company now expects much lower utilization will result in 2013. The impact of the new law will be reflected in the Company's 2013 Consolidated Financial Statements as a decrease in Current Deferred Tax Assets with a corresponding increase in Deferred Tax Liabilities related to the net operating loss.

In January 2013, OG&E learned that a portion of certain Oklahoma investment tax credits previously recognized but not yet utilized may not be available for utilization in future years. If management determines that it is more likely than not that it will be unable to utilize these credits, OG&E will be required to record a reserve of \$7.8 million (\$5.1 million after tax) at such time.

## 11. Common Equity

### Automatic Dividend Reinvestment and Stock Purchase Plan

The Company issued 246,549 shares of common stock under its Automatic Dividend Reinvestment and Stock Purchase Plan in 2012 and received proceeds of \$13.4 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, 2012, there were 2,122,494 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)	2012	2011	2010
Net income attributable to OGE Energy	\$355.0	\$342.9	\$295.3
<b>Average common shares outstanding</b>			
Basic average common shares outstanding	98.6	97.9	97.3
Effect of dilutive securities:			
Contingently issuable shares (performance units)	0.5	1.3	1.6
Diluted average common shares outstanding	99.1	99.2	98.9
Basic earnings per average common share attributable to OGE Energy common shareholders	\$ 3.60	\$ 3.50	\$ 3.03
Diluted earnings per average common share attributable to OGE Energy common shareholders	\$ 3.58	\$ 3.45	\$ 2.99
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, 2012, the Company was in compliance with all of its debt agreements.

### OG&E Industrial Authority Bonds

OG&E has tax-exempt pollution control bonds with optional redemption provisions that allow the holders to request repayment of the bonds on any business day. 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% - 0.40%	Garfield Industrial Authority, January 1, 2025	\$ 47.0
0.21% - 0.41%	Muskogee Industrial Authority, January 1, 2025	32.4
0.20% - 0.47%	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.

### Enogex Term Loan Agreement

On August 2, 2012, Enogex entered into a \$250 million, three-year term loan agreement with a maturity date of August 2, 2015. The loan was used to fund capital expenditures and for working capital purposes.

### Long-Term Debt Maturities

Maturities of the Company's long-term debt during the next five years consist of \$0.2 million, \$300.2 million, \$250.2 million, \$110.2 million and \$125.2 million in years 2013, 2014, 2015, 2016 and 2017, respectively.

The Company has previously incurred costs related to debt refinancings. Unamortized loss on reacquired debt is classified as a Non-Current Regulatory Asset, unamortized debt expense is 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.

### 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 \$430.9 million and \$277.1 million at December 31, 2012 and 2011, respectively, at a weighted-average interest rate of 0.43 percent and 0.48 percent, respectively. The following table provides information regarding the Company's revolving credit agreements and available cash at December 31, 2012.

(In millions)	Aggregate Commitment	Amount Outstanding <sup>(A)</sup>	Weighted-Average Interest Rate	Maturity
<b>Revolving credit agreements and available cash</b>				
OGE Energy <sup>(B)</sup>	\$ 750.0	\$430.9	0.43% <sup>(E)</sup>	12/13/16
OG&E <sup>(C)</sup>	400.0	2.2	0.53% <sup>(E)</sup>	12/13/16
Enogex LLC <sup>(D)</sup>	400.0	—	—% <sup>(E)</sup>	12/13/16
	1,550.0	433.1	0.43%	
Cash	1.8	N/A	N/A	N/A
<b>Total</b>	<b>\$1,551.8</b>	<b>\$433.1</b>	<b>0.43%</b>	

<sup>(A)</sup> Includes direct borrowings under the revolving credit agreements, commercial paper borrowings and letters of credit at December 31, 2012.

<sup>(B)</sup> 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, 2012, there was \$430.9 million in outstanding commercial paper borrowings.

<sup>(C)</sup> 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, 2012, there was \$2.2 million supporting letters of credit.

<sup>(D)</sup> 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.

<sup>(E)</sup> Represents the weighted-average interest rate for the outstanding borrowings under the revolving credit agreements, commercial paper borrowings and letters of credit.

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 rating 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 could also lead to higher long-term borrowing costs and, if below investment grade, would require the Company to post 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, 2013 and ending December 31, 2014.

### 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 2012 and 2011, OGE Energy made contributions to its Pension Plan of \$35 million and \$50 million, respectively, 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 2013, OGE Energy expects to contribute up to \$35 million to its Pension Plan. The expected contribution to the Pension Plan during 2013 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 of the Internal Revenue Code of 1986 ("Code"). Participants in the Restoration of Retirement Income Plan receive the same benefits that they would have received under the Company's Pension Plan in the absence of limitations imposed by the Federal tax laws. 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, 2012 and 2011. 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)	Pension Plan		Restoration of Retirement Income Plan	
	2012	2011	2012	2011
Benefit obligations	<b>\$(747.1)</b>	\$(697.7)	<b>\$(14.5)</b>	\$(13.3)
Fair value of plan assets	<b>626.0</b>	589.8	-	-
Funded status at end of year	<b>\$(121.1)</b>	\$(107.9)	<b>\$(14.5)</b>	\$(13.3)

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
2013	\$ 75.1
2014	94.5
2015	84.7
2016	77.2
2017	71.5
After 2017	295.3

### 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 Long Government/Credit
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, 2012 and 2011. There were no Level 3 investments held by the Pension Plan at December 31, 2012 and 2011.

(In millions, December 31)	2012	Level 1	Level 2
Common stocks			
U.S. common stocks	\$232.2	\$232.2	\$ -
Foreign common stocks	39.9	39.9	-
U.S. Government obligations			
U.S. treasury notes and bonds <sup>(A)</sup>	138.6	138.6	-
Mortgage-backed securities	55.8	-	55.8
Bonds, debentures and notes <sup>(B)</sup>			
Corporate fixed income and other securities	98.4	-	98.4
Mortgage-backed securities	13.5	-	13.5
Commingled fund <sup>(C)</sup>	34.9	-	34.9
Common/collective trust <sup>(D)</sup>	25.6	-	25.6
Foreign government bonds	3.9	-	3.9
U.S. municipal bonds	0.8	-	0.8
Interest-bearing cash	0.2	0.2	-
Forward contracts			
Receivable (foreign currency)	0.4	-	0.4
Payable (foreign currency)	(0.4)	-	(0.4)
<b>Total Plan investments</b>	<b>\$643.8</b>	<b>\$410.9</b>	<b>\$232.9</b>
Receivable from broker for securities sold	0.8		
Interest and dividends receivable	2.8		
Payable to broker for securities purchased	(21.4)		
<b>Total Plan assets</b>	<b>\$626.0</b>		



(In millions, December 31)	2011	Level 1	Level 2
<b>Common stocks</b>			
U.S. common stocks	\$179.7	\$179.7	\$ -
Foreign common stocks	59.5	59.5	-
<b>U.S. Government obligations</b>			
U.S. treasury notes and bonds <sup>(A)</sup>	118.8	118.8	-
Mortgage-backed securities	72.0	-	72.0
Other securities	1.0	-	1.0
<b>Bonds, debentures and notes<sup>(B)</sup></b>			
Corporate fixed income and other securities	95.3	-	95.3
Mortgage-backed securities	17.2	-	17.2
Commingled fund <sup>(C)</sup>	38.5	-	38.5
Common/collective trust <sup>(D)</sup>	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	-
<b>Forward contracts</b>			
Receivable (foreign currency)	4.1	-	4.1
Payable (foreign currency)	(4.1)	-	(4.1)
<b>Total Plan investments</b>	<b>\$618.9</b>	<b>\$360.7</b>	<b>\$258.2</b>
Receivable from broker for securities sold	4.8		
Interest and dividends receivable	3.1		
Payable to broker for securities purchased	(37.0)		
<b>Total Plan assets</b>	<b>\$589.8</b>		

(A) 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.

(B) 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.

(C) This category represents units of participation in a commingled fund that primarily invested in stocks of international companies and emerging markets.

(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.

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

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. 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, the Company's contribution to the 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, Medicare-eligible retirees are no longer eligible to participate in the retiree medical plan. Instead, the Company began providing Medicare-eligible retirees and their Medicare-eligible spouses an annual fixed contribution to a Company-sponsored health reimbursement arrangement. The contribution was determined based on the Company's expected average 2011 premium for medical and drug coverage. Medicare-eligible retirees are able to purchase individual insurance policies supplemental to Medicare through a third-party administrator and use their health reimbursement arrangement funds for reimbursement of medical premiums and other eligible medical expenses. 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, 2012 and 2011. There were no Level 2 investments held by the postretirement benefit plans at December 31, 2012 and 2011.

(In millions, December 31)	2012	Level 1	Level 3
Group retiree medical insurance contract <sup>(A)</sup>	\$53.3	\$ -	\$53.3
Mutual funds investment			
U.S. equity investments	6.0	6.0	-
Money market funds investment	0.3	0.3	-
<b>Total Plan investments</b>	<b>\$59.6</b>	<b>\$6.3</b>	<b>\$53.3</b>

<sup>(A)</sup> 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)	2011	Level 1	Level 3
Group retiree medical insurance contract <sup>(A)</sup>	\$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	-
<b>Total Plan investments</b>	<b>\$61.0</b>	<b>\$6.7</b>	<b>\$54.3</b>

<sup>(A)</sup> 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)	2012
<b>Group retiree medical insurance contract</b>	
Beginning balance	\$54.3
Net unrealized gains related to instruments held at the reporting date	5.5
Interest income	1.2
Dividend income	0.6
Realized gains	0.6
Administrative expenses and charges	(0.1)
Claims paid	(8.8)
<b>Ending balance</b>	<b>\$53.3</b>

The following table presents the status of the Company's postretirement benefit plans at December 31, 2012 and 2011. 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)	2012	2011
Benefit obligations	\$(301.0)	\$(280.6)
Fair value of plan assets	59.6	61.0
<b>Funded status at end of year</b>	<b>\$(241.4)</b>	<b>\$(219.6)</b>

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 8.55 percent in 2013 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)	2012	2011	2010
<b>One-percentage point increase</b>			
Effect on aggregate of the service and interest cost components	\$ -	\$ -	\$3.1
Effect on accumulated postretirement benefit obligations	0.1	0.1	0.7
<b>One-percentage point decrease</b>			
Effect on aggregate of the service and interest cost components	\$0.1	\$0.1	\$2.5
Effect on accumulated postretirement benefit obligations	0.9	0.6	1.6

## Medicare Prescription Drug, Improvement and Modernization Act of 2003

The Medicare Prescription Drug, Improvement and Modernization Act of 2003 expanded 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.

(In millions)	Gross Projected Postretirement Benefit Payments
2013	\$15.4
2014	16.3
2015	17.0
2016	17.6
2017	18.1
After 2017	94.9

## 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 2012 and 2011. 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, 2012 was \$705.2 million and \$12.7 million, respectively. 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 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	
	2012	2011	2012	2011	2012	2011
(In millions, December 31)						
<b>Change in benefit obligation</b>						
Beginning obligations	<b>\$(697.7)</b>	\$(640.9)	<b>\$(13.3)</b>	\$(10.8)	<b>\$(280.6)</b>	\$(337.1)
Service cost	<b>(17.9)</b>	(17.6)	<b>(1.0)</b>	(1.0)	<b>(4.1)</b>	(3.5)
Interest cost	<b>(30.1)</b>	(33.3)	<b>(0.6)</b>	(0.6)	<b>(11.9)</b>	(12.5)
Plan amendments	-	-	-	-	-	91.4
Participants' contributions	-	-	-	-	<b>(3.5)</b>	(8.1)
Medicare subsidies received	-	-	-	-	<b>(0.5)</b>	(2.0)
Actuarial gains (losses)	<b>(61.4)</b>	(48.3)	<b>(1.8)</b>	(1.0)	<b>(12.9)</b>	(25.7)
Benefits paid	<b>60.0</b>	42.4	<b>2.2</b>	0.1	<b>12.5</b>	16.9
Ending obligations	<b>\$(747.1)</b>	\$(697.7)	<b>\$(14.5)</b>	\$(13.3)	<b>\$(301.0)</b>	\$(280.6)
<b>Change in plans' assets</b>						
Beginning fair value	<b>\$ 589.8</b>	\$ 574.0	<b>\$ -</b>	\$ -	<b>\$ 61.0</b>	\$ 58.5
Actual return on plans' assets	<b>61.2</b>	8.2	-	-	<b>4.5</b>	2.7
Employer contributions	<b>35.0</b>	50.0	<b>2.2</b>	0.1	<b>2.6</b>	6.6
Participants' contributions	-	-	-	-	<b>3.5</b>	8.1
Medicare subsidies received	-	-	-	-	<b>0.5</b>	2.0
Benefits paid	<b>(60.0)</b>	(42.4)	<b>(2.2)</b>	(0.1)	<b>(12.5)</b>	(16.9)
Ending fair value	<b>\$ 626.0</b>	\$ 589.8	<b>\$ -</b>	\$ -	<b>\$ 59.6</b>	\$ 61.0
Funded status at end of year	<b>\$(121.1)</b>	\$(107.9)	<b>\$(14.5)</b>	\$(13.3)	<b>\$(241.4)</b>	\$(219.6)

## Net Periodic Benefit Cost

	Pension Plan			Restoration of Retirement Income Plan			Postretirement Benefit Plans		
	2012	2011	2010	2012	2011	2010	2012	2011	2010
(In millions, year ended December 31)									
Service cost	<b>\$ 17.9</b>	\$ 17.6	\$ 16.7	<b>\$1.0</b>	\$1.0	\$0.9	<b>\$ 4.1</b>	\$ 3.5	\$ 4.3
Interest cost	<b>30.1</b>	33.3	31.8	<b>0.6</b>	0.6	0.5	<b>11.9</b>	12.5	17.0
Expected return on plan assets	<b>(46.0)</b>	(45.5)	(42.4)	-	-	-	<b>(3.0)</b>	(5.1)	(6.9)
Amortization of transition obligation	-	-	-	-	-	-	<b>2.7</b>	2.7	2.7
Amortization of net loss	<b>23.8</b>	19.2	21.3	<b>0.4</b>	0.4	0.3	<b>20.6</b>	18.3	12.1
Amortization of unrecognized prior service cost <sup>(A)</sup>	<b>2.2</b>	2.4	2.4	<b>0.7</b>	0.7	0.7	<b>(16.5)</b>	(16.5)	-
Settlement	-	-	-	<b>0.9</b>	-	-	-	-	-
Net periodic benefit cost <sup>(B)</sup>	<b>\$ 28.0</b>	\$ 27.0	\$ 29.8	<b>\$3.6</b>	\$2.7	\$2.4	<b>\$ 19.8</b>	\$ 15.4	\$29.2

<sup>(A)</sup> 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.

<sup>(B)</sup> In addition to the \$51.4 million, \$45.1 million and \$61.4 million of net periodic benefit cost recognized in 2012, 2011 and 2010, respectively, the Company recognized the following:

- An increase in pension expense in 2012, 2011 and 2010 of \$8.3 million, \$10.8 million and \$8.1 million, respectively, 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); and
- An increase in postretirement medical expense in 2012 and 2011 of \$0.8 million and \$3.5 million, respectively, 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 \$6.5 million, \$6.1 million and \$6.5 million at December 31, 2012, 2011 and 2010, respectively. The capitalized portion of the net periodic postretirement benefit cost was \$5.5 million, \$3.8 million and \$6.5 million at December 31, 2012, 2011 and 2010, respectively.

## Rate Assumptions

(Year ended December 31)	Pension Plan and Restoration of Retirement Income Plan			Postretirement Benefit Plans		
	2012	2011	2010	2012	2011	2010
Discount rate	<b>3.70%</b>	4.50%	5.30%	<b>3.60%</b>	4.50%	5.30%
Rate of return on plans' assets	<b>8.00%</b>	8.00%	8.50%	<b>4.00%</b>	6.50%	8.50%
Compensation increases	<b>4.20%</b>	4.40%	4.40%	<b>N/A</b>	N/A	N/A
Assumed health care cost trend:						
Initial trend	<b>N/A</b>	N/A	N/A	<b>8.55%</b>	8.75%	8.99%
Ultimate trend rate	<b>N/A</b>	N/A	N/A	<b>4.48%</b>	4.48%	5.00%
Ultimate trend year	<b>N/A</b>	N/A	N/A	<b>2028</b>	2028	2020

N/A - not applicable

The overall expected rate of return on plan assets assumption remained at 8.00 percent in 2011 and 2012 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 \$2.6 million and \$2.4 million at December 31, 2012 and 2011, 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 certain limitations of the Code. Participants may designate, at their discretion, all or any portion of their contributions as: (i) a before-tax contribution under Section 401(k) of the Code subject to the limitations thereof; or (ii) a contribution made on an after-tax basis. The 401(k) Plan also includes 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 future salary deferral rate to be 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 participants could select from the options below.

Employment Date	Option 1	Option 2	Option 3
Before February 1, 2000	< 20 years of service – 50% Company match up to 6% of compensation	200% Company match up to 5% of compensation	100% Company match up to 6% of compensation
	> 20 years of service – 75% Company match up to 6% of compensation	200% Company match up to 5% of compensation	100% Company match up to 6% of compensation
After February 1, 2000 and before December 1, 2009	100% Company match up to 6% of compensation	200% Company match up to 5% of compensation	N/A
After December 1, 2009	200% Company match up to 5% of compensation	N/A	N/A

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. Once made, 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 the 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 \$13.4 million, \$12.3 million and \$11.4 million in 2012, 2011 and 2010, 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 in the qualified 401(k) Plan 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 three years or, if earlier, on retirement, disability, death, a change in control of the Company or termination of the plan. Deferrals, plus any Company match, are credited to a record-

keeping account in the participant's name. Earnings on the deferrals are indexed to the assumed investment funds selected by the participant. In 2012, those investment options included a Company Common Stock fund, whose value was determined based on the stock price of the Company's Common Stock, and various money market, bond and equity funds. 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 limitations of the Code.

#### **15. Report of Business Segments**

Previously, the Company's business was divided into four segments 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. During the third quarter of 2012, the operations and activities of EER were fully integrated with those of Enogex through the creation of a new commodity management organization. The operations of EER, including asset management activities, have been included in the natural gas transportation and storage segment and have been restated for all prior periods presented. As a result of this change, the Company's business is now divided into three segments for financial reporting purposes as follows: (i) electric utility, (ii) natural gas transportation and storage and (iii) natural gas gathering and processing. 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, 2012, 2011 and 2010.

(In millions)	Electric Utility	Natural Gas Transportation and Storage	Natural Gas Gathering and Processing	Other Operations	Eliminations	Total
<b>2012</b>						
Operating revenues	\$2,141.2	\$ 639.5	\$1,222.6	\$ -	\$ (332.1)	\$3,671.2
Cost of goods sold	879.1	504.9	868.7	-	(334.0)	1,918.7
Gross margin on revenues	1,262.1	134.6	353.9	-	1.9	1,752.5
Other operation and maintenance	446.3	49.8	123.1	(17.7)	-	601.5
Depreciation and amortization	248.7	24.0	84.8	13.5	-	371.0
Impairment of assets	-	-	0.4	-	-	0.4
Gain on insurance proceeds	-	-	(7.5)	-	-	(7.5)
Taxes other than income	77.7	15.7	12.6	4.2	-	110.2
Operating income (loss)	\$ 489.4	\$ 45.1	\$ 140.5	\$ -	\$ 1.9	\$ 676.9
Total assets	\$7,222.4	\$2,330.8	\$1,868.6	\$272.6	\$(1,772.2)	\$9,922.2
Capital expenditures <sup>(A)</sup>	\$ 704.4	\$ 32.0	\$ 475.4	\$ 18.3	\$ (0.9)	\$1,229.2
<b>2011</b>						
Operating revenues	\$2,211.5	\$ 880.1	\$1,167.1	\$ -	\$ (342.8)	\$3,915.9
Cost of goods sold	1,013.5	736.0	870.7	-	(342.3)	2,277.9
Gross margin on revenues	1,198.0	144.1	296.4	-	(0.5)	1,638.0
Other operation and maintenance	436.0	50.7	111.8	(17.3)	-	581.2
Depreciation and amortization	216.1	22.0	55.6	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	15.0	7.0	4.1	-	99.7
Operating income (loss)	\$ 472.3	\$ 56.4	\$ 118.7	\$ (0.2)	\$ (0.5)	\$ 646.7
Total assets	\$6,620.9	\$1,836.9	\$1,483.8	\$166.6	\$(1,202.2)	\$8,906.0
Capital expenditures <sup>(B)</sup>	\$ 844.5	\$ 41.1	\$ 572.0	\$ 13.8	\$ (0.6)	\$1,470.8
<b>2010</b>						
Operating revenues	\$2,109.9	\$ 984.8	\$1,005.6	\$ -	\$ (383.4)	\$3,716.9
Cost of goods sold	1,000.2	834.5	733.3	-	(380.6)	2,187.4
Gross margin on revenues	1,109.7	150.3	272.3	-	(2.8)	1,529.5
Other operation and maintenance	418.1	53.8	91.5	(13.6)	-	549.8
Depreciation and amortization	208.7	21.2	50.1	11.3	-	291.3
Impairment of assets	-	0.7	0.4	-	-	1.1
Taxes other than income	69.2	14.2	6.4	3.6	-	93.4
Operating income (loss)	\$ 413.7	\$ 60.4	\$ 123.9	\$ (1.3)	\$ (2.8)	\$ 593.9
Total assets	\$5,898.1	\$1,316.6	\$ 973.8	\$135.4	\$(654.8)	\$7,669.1
Capital expenditures	\$ 631.6	\$ 72.6	\$ 164.0	\$ 14.1	\$ (2.4)	\$ 879.9

<sup>(A)</sup> Includes \$78.6 million related to the acquisition of certain gas gathering assets as discussed in Note 3.

<sup>(B)</sup> 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, OG&E wind farm land leases and OGE Energy and Enogex noncancellable operating leases. Future minimum payments for noncancellable operating leases are as follows:

(In millions, year ended December 31)	2013	2014	2015	2016	2017	After 2017	Total
Operating lease obligations							
OG&E railcars	\$ 3.2	\$2.8	\$2.7	\$27.3	\$ -	\$ -	\$ 36.0
OG&E wind farm land leases	2.0	2.1	2.1	2.1	2.4	51.2	61.9
OGE Energy noncancellable operating lease	0.3	0.8	0.8	0.8	0.8	0.7	4.2
Enogex noncancellable operating leases	5.2	3.7	3.5	3.4	0.7	-	16.5
Total operating lease obligations:	\$10.7	\$9.4	\$9.1	\$33.6	\$3.9	\$51.9	\$118.6

Payments for operating lease obligations were \$14.2 million, \$10.4 million and \$10.3 million for the years ended December 31, 2012, 2011 and 2010, respectively.

### OG&E Railcar Lease Agreement

OG&E has a noncancellable operating lease with purchase options, covering 1,389 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.

On January 11, 2012, OG&E executed a five-year lease agreement for 135 railcars to replace railcars that have been taken out of service or destroyed. 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.

### OG&E Wind Farm Land Lease Agreements

OG&E has wind farm land operating leases for its Centennial, OU Spirit and Crossroads wind farms expiring at various dates. The Centennial lease has rent escalations which increase annually based on the Consumer Price Index. The OU Spirit and Crossroads leases have rent escalations which increase after five and 10 years. Although the leases are cancellable,

OG&E is required to make annual lease payments as long as the wind turbines are located on the land. OG&E does not expect to terminate the leases until the wind turbines reach the end of their economic life.

### OGE Energy Noncancellable Operating Lease

On August 29, 2012, OGE Energy executed a five-year lease agreement for office space from September 1, 2013 to August 31, 2018. This lease has rent escalations which increase after five years and allows for leasehold improvements.

### Enogex Noncancellable Operating Leases

Enogex currently occupies 134,219 square feet of office space at its executive offices under a lease that expires March 31, 2017. The lease payments are \$11.3 million over the lease term which began April 1, 2012. This lease has rent escalations which increase after five and 10 years if the lease is renewed.

Enogex currently has 17 compression service agreements, of which 10 agreements are on a month-to-month basis, three agreements will expire in 2013, two agreements will expire in 2016 and two agreements will expire in 2017. Enogex also has eight gas treating agreements, of which six agreements are on a month-to-month basis, one agreement will expire in 2013 and one agreement will expire in 2014.

### Other Purchase Obligations and Commitments

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

(In millions)	2013	2014	2015	2016	2017	Total
Other purchase obligations and commitments						
OG&E cogeneration capacity and fixed operation and maintenance payments	\$ 87.9	\$ 85.8	\$ 84.5	\$ 82.4	\$ 80.1	\$ 420.7
OG&E expected cogeneration energy payments	58.6	63.8	70.5	81.0	87.3	361.2
OG&E minimum fuel purchase commitments	405.0	255.0	264.8	-	-	924.8
OG&E expected wind purchase commitments	57.5	58.0	58.9	59.8	60.8	295.0
OG&E long-term service agreement commitments	8.0	27.8	6.7	6.2	6.4	55.1
EER commitments	11.9	10.8	4.7	0.8	-	28.2
Total other purchase obligations and commitments	\$628.9	\$501.2	\$490.1	\$230.2	\$234.6	\$2,085.0

### Public Utility Regulatory Policy Act of 1978

At December 31, 2012, 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, 2012, 2011 and 2010, OG&E made total payments to cogenerators of \$135.1 million, \$140.7 million and \$147.3 million, respectively, of which \$77.1 million, \$78.0 million and \$80.7 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 \$585.6 million, \$647.6 million and \$721.4 million for the years ended December 31, 2012, 2011 and 2010, respectively. OG&E has coal contracts for purchases from January 2012 through December 2015. OG&E has entered into multiple month term natural gas contracts for 26.1 percent of its 2013 annual forecasted natural gas requirements. Additional gas supplies to fulfill OG&E's remaining 2013 natural gas requirements will be acquired through additional requests for proposal in early to mid-2013, 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 120 MW Centennial wind farm, (ii) the 101 MW OU Spirit wind farm, (iii) the 227.5 MW 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, (vi) access to up to 130 MWs of electricity generated at a wind farm in Dewey County, Oklahoma from a 20-year contract OG&E entered into with Edison Mission Energy that expires in 2030 and (vii) access to up to 60 MWs of electricity generated at a wind farm near Blackwell, Oklahoma from a 20-year contract OG&E entered into with NextEra Energy that expires in 2032.

The following table summarizes OG&E's wind power purchases for the years ended December 31, 2012, 2011 and 2010.

(In millions, year ended December 31)	2012	2011	2010
CPV Keenan	\$25.1	\$24.5	\$3.8
Edison Mission Energy	20.2	8.5	–
FPL Energy	3.4	3.7	3.9
NextEra Energy	0.8	–	–
Total wind power purchased	\$49.5	\$36.7	\$7.7

### 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 2027. The contract requires payments based on both a fixed and variable cost component, depending on how much the Redbud Plant is used.

### EER Commitments

In 2004, EER 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, EER and Cheyenne Plains amended the firm transportation service agreement to provide for EER to turn back 20,000 decatherms/day of its capacity beginning in January 2008 for the remainder of the term.

In 2006, Enogex entered into a firm capacity 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 capacity agreement is currently 272 MMcf/d, with the quantity subject to being increased by mutual agreement pursuant to the capacity agreement. In 2009, EER 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.



## 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 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 required 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 or claims made by third parties, including governmental 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. At the present time, based on currently available information, except as otherwise stated above, in Note 17 below, in Item 3 of the Company's Form 10-K and under "Environmental Laws and Regulations" in "Management's Discussion of Financial Condition and Results of Operations", the Company believes that any reasonably possible losses in excess of accrued amounts arising out of pending or threatened lawsuits or claims would not be quantitatively material to its financial statements and would not 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 2012, 87 percent of OG&E's electric revenue was subject to the jurisdiction of the OCC, eight percent to the APSC and five 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 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 called 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 Energy built, owns and operates the wind farm and OG&E purchases the electric output. On February 22, 2012, OG&E, the Attorney General and the Public Utility Division of the OCC signed a settlement agreement whereby the stipulating parties requested that the OCC issue an order approving the agreement for electric service with Oklahoma State University. On March 12, 2012, OG&E received an order from the OCC approving the settlement agreement. Pursuant to the terms of the power purchase agreement between OG&E and NextEra Energy, OG&E has been purchasing the electric output of the wind farm since November 2012 and uses that power to provide service to Oklahoma State University and its other retail customers. The wind farm was fully in service in December 2012.

#### OG&E SPP Transmission 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 below.

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 originating at OG&E's existing Sooner 345 kilovolt substation and proceeding 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 connects to the companion line constructed in Kansas by Westar Energy. The transmission line was placed in service in April 2012. The total capital expenditures associated with this project were \$45 million.

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 extends 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 transmission line was completed in April 2012. The total capital expenditures associated with this project were \$157 million.

As discussed below, the OCC approved a settlement agreement in OG&E's 2011 Oklahoma rate case filing that included an expedited procedure for recovering the costs of the two projects. On July 31, 2012, OG&E filed an application with the OCC requesting an order authorizing recovery for the two projects through the SPP transmission systems additions rider. On October 2, 2012, all parties signed a settlement

agreement in this matter which stated: (i) the parties agree not to oppose requested relief sought by OG&E, (ii) OG&E will host meetings to discuss the SPP's transmission planning process, including any future transmission projects for which OG&E has received a notice to construct from the SPP, and (iii) there will be opportunities for parties to provide input related to transmission planning studies that the SPP performs to identify future transmission projects. On October 25, 2012, the OCC issued an order approving the settlement agreement and granting OG&E cost recovery for the two projects. OG&E initiated cost recovery beginning with the first billing cycle in November 2012.

#### OG&E 2011 Oklahoma Rate Case Filing

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 requested a return on equity of 11.0 percent based on a common equity percentage of 53.0 percent. In its application, OG&E requested recovery of 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 July 2, 2012, OG&E and other parties associated with its rate increase reached a settlement agreement in this matter. On July 9, 2012, the OCC issued an order approving the settlement agreement in this matter. Key terms of the settlement agreement included: (i) an annual net increase of approximately \$4.3 million in OG&E's rates to its Oklahoma retail customers, (ii) OG&E's Oklahoma retail authorized return on equity of 10.2 percent, (iii) the rate of return under various recovery riders previously approved by the OCC, including riders for OG&E's smart grid implementation and Crossroads wind farm, is based on OG&E's actual debt and equity ratios as reflected in OG&E's application and a 10.2 percent return on equity, (iv) depreciation rates were implemented in the same month new customer rates went into effect, (v) the pension and postretirement medical cost tracker remains in effect, (vi) a procedure was established to expedite the recovery of the cost of specified high-voltage transmission projects and (vii) extension of funding for OG&E's system hardening program. OG&E expects the impact of the rate increase on its customers and service territory to be minimal as the rate increase will be more than offset by lower fuel costs attributable to prior fuel over recoveries from lower than forecasted fuel costs. OG&E implemented the new rates effective in early August.

#### 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. On August 3, 2011, the APSC issued an order in this matter approving the settlement agreement. On November 5, 2012, OG&E filed a revised smart grid recovery rider rate schedule. On December 13, 2012, the APSC issued an order in this matter approving the revised smart grid recovery rider to be effective beginning with the first billing cycle in January 2013 through December 2013. OG&E began recovering the 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. The APSC also found that the prudence of OG&E's smart grid expenditures will be determined in OG&E's next Arkansas rate case and that revenues collected under the rider are subject to refund, with interest, only in the event that the APSC determines that OG&E's smart grid expenditures were not prudent. The costs recoverable from Oklahoma customers for system-wide deployment of smart grid technology and implementing the smart grid pilot program were 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 in OG&E's next general rate case. This project was completed in late 2012 and the smart grid project costs did not exceed \$366.4 million.

#### OG&E Demand and Energy Efficiency Program Filing

On July 2, 2012, OG&E filed an application with the OCC requesting approval of OG&E's 2013 demand portfolio, the authorization to recover the program costs, lost revenues associated with any achieved energy, demand savings and performance based incentives through the demand program rider and the recovery of costs associated with research and development investments. On July 16, 2012, OG&E filed an amended application which modified various calculations to reflect the rate of return authorized by the OCC in OG&E's 2011 rate case order and provided for consideration of a peak time rebate program. On December 20, 2012, the OCC approved a settlement with all parties in this matter.

Key terms of the settlement included (i) approval of the program budgets proposed by OG&E and an additional amount of approximately \$7 million over the three-year period for the energy efficiency programs, (ii) approval of OG&E's proposed Demand Program Rider tariff, (iii) the recovery through the Demand Program Rider of the increased program costs and the net lost revenues, incentives and research and development investments requested by OG&E, with the exception of lost revenues resulting from the Integrated Volt Var Control program (automated intelligence to control voltage and power on the distribution lines) and incentives for the SmartHours™ and Integrated Volt Var Control demand response programs, (iv) recovery of the program costs on a levelized basis over the three-year period, (v) consideration of implementing a peak time rebate program in 2015 and (vi) the periodic filing of additional reports. The Demand Program Rider became effective on January 1, 2013.

#### OG&E Fuel Adjustment Clause Review for Calendar Year 2010

The OCC routinely reviews the costs recovered from customers through OG&E's fuel adjustment clause. On August 19, 2011, the OCC Staff filed an application to review OG&E's fuel adjustment clause for calendar year 2010, including the prudence of OG&E's electric generation, purchased power and fuel procurement costs. OG&E responded by filing direct testimony and the minimum filing review package on October 18, 2011. On September 26, 2012, the administrative law judge recommended that the OCC find that for the calendar year 2010 OG&E's generation, purchase power and fuel procurement processes and costs, including the cost of replacement power for the Sooner 2 outage, were prudent and no disallowance (as discussed below) for any of these expenses is warranted. On January 31, 2013, the OCC issued an order approving the administrative law judge's recommendation. Previously, the Oklahoma Industrial Energy Consumers recommended that the OCC disallow recovery of approximately \$44 million of costs previously recovered through OG&E's fuel adjustment clause. These recommendations were based on allegations that OG&E's lower cost coal-fired generation was underutilized, that OG&E failed to aggressively pursue purchasing power at a cost lower than its marginal cost of generation and that OG&E should be found imprudent related to an unplanned outage at OG&E's Sooner 2 coal unit in November and December 2010. Previously, the OCC Staff recommended approval of OG&E's actions related to utilization of coal plants and practices related to purchasing power but recommended that OG&E refund \$3 million to customers because of the Sooner 2 outage.

#### 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. On July 6, 2012, Enogex submitted a compliance filing to synchronize the 2011 fuel filing with the revised statement of operating conditions filed on May 31, 2012 in compliance with the FERC's order approving Enogex's 2011 Section 311 rate case settlement. In October 2012, the FERC accepted Enogex's proposed zonal fuel percentages.

#### Enogex 2012 Fuel Filing

On February 24, 2012, Enogex submitted its annual fuel filing to establish the fixed fuel percentages for its East Zone and West Zone for the 2012 fuel year (April 1, 2012 through March 31, 2013). On July 6, 2012, Enogex submitted a compliance filing to synchronize the 2012 fuel filing with the revised statement of operating conditions filed on May 31, 2012 in compliance with the FERC's order approving Enogex's 2011 Section 311 rate case settlement. In October 2012, the FERC accepted Enogex's proposed zonal fuel percentages.

#### Enogex Storage Statement of Operating Conditions Filing

On August 31, 2010, Enogex filed a new statement of operating conditions applicable to storage services with the FERC 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. On December 7, 2012, the FERC issued an order approving Enogex's revised storage statement of operating conditions, effective August 31, 2010.

#### 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. On January 10, 2012, Enogex filed a settlement agreement with the FERC. On May 4, 2012, the FERC issued an order approving the settlement agreement in this matter, subject to the submission of a compliance filing to place the settlement rates into effect as of March 1, 2011, which compliance filing was subsequently filed on May 31, 2012. The FERC also requested that Enogex file a revised statement of operating conditions, which was subsequently filed on May 31, 2012. As part of the settlement agreement in this

matter, Enogex made refunds of \$0.2 million to affected customers on June 15, 2012 and submitted a report to the FERC on July 6, 2012 showing the refund payment calculation. On February 21, 2013, the FERC issued an order approving the refund report.

#### **Pending Regulatory Matters**

##### **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 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 inter-regional 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. These changes to the "right of first refusal" apply 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 were filed on November 13, 2012.

OGE Energy cannot, at this time, determine the precise impact of Order No. 1000 on OG&E. OG&E has filed a petition for review in the D.C. Circuit relating to the same matter. 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.

##### **OG&E Market-Based Rate Authority**

On June 29, 2012, OG&E filed its triennial market power update with the FERC to retain its market-based rate authorization in the SPP's energy imbalance service market but to surrender its market-based rate authorization for any market-based rate sales outside the SPP's energy imbalance service market. A FERC order is pending.

##### **OG&E Fuel Adjustment Clause Review for Calendar Year 2011**

On July 31, 2012, the OCC Staff filed an application for a public hearing to review and monitor OG&E's application of the 2011 fuel adjustment clause and for a prudence review of OG&E's electric generation, purchased power and fuel procurement processes and costs in calendar year 2011. OG&E filed the necessary information and documents needed to satisfy the OCC's minimum filing requirement rules on October 1, 2012. On December 19, 2012, witnesses for the OCC Staff filed responsive testimony recommending that the OCC approve OG&E's fuel adjustment clause costs and recoveries for the calendar year 2011 and recommending that the OCC find that OG&E's electric generation, purchased power, fuel procurement and other fuel related practices, policies and decisions during calendar year 2011 were fair, just and reasonable and prudent. The Oklahoma Industrial Energy Consumers filed a statement of position on December 19, 2012 and did not challenge OG&E's application of its fuel adjustment clause or prudence. The Oklahoma Industrial Energy Consumers reserved its right to file rebuttal testimony, cross examine witnesses and amend its statement of position should circumstances change or additional information becomes available in the course of this proceeding. On January 7, 2013, the Oklahoma Attorney General filed a statement of position stating that after reviewing the case information the Attorney General has no reason at this time to dispute the findings of the OCC Staff. A hearing in this matter is scheduled for April 4, 2013.

##### **OG&E Crossroads Wind Farm**

As previously reported, OG&E signed memoranda of understanding in February 2010 for approximately 197.8 MWs of wind turbine generators and certain related balance of plant engineering, procurement and construction services associated with the Crossroads wind farm. Also as part of this project, on June 16, 2011, OG&E entered into an interconnection agreement with the SPP for the Crossroads wind farm which allowed the Crossroads wind farm to interconnect at 227.5 MWs. On

August 31, 2012, OG&E filed an application with the APSC requesting approval to recover the Arkansas portion of the costs of the Crossroads wind farm through a rider until such costs are included in OG&E's base rates as part of its next general rate proceeding. On December 14, 2012, the APSC Staff filed testimony recommending that the APSC find that the Crossroads wind farm is in the public interest and that it approve interim recovery through the Energy Cost Recovery Rider effective August 31, 2012. OG&E concurred with the APSC Staff's recommendations. On January 16, 2013, the APSC granted a motion made by OG&E and the APSC Staff to cancel the hearing previously scheduled and issue an order based on the filed record. On February 22, 2013, the APSC directed OG&E to respond to two questions in order to complete the record upon which they may rule. OG&E believes it is reasonable to expect a final order from the APSC by the end of the first quarter.

**OG&E Fuel Adjustment Clause Review for Calendar Year 2009  
Related to Enogex Gas Transportation and Storage Agreement**

As previously reported, under the terms of a settlement agreement reached in 2011 regarding the prudence of OG&E's fuel adjustment clause for 2009, OG&E agreed to hire a third party expert to evaluate its prospective gas transportation and storage needs and to identify options for meeting those needs. Upon completion of the third party evaluation, OG&E agreed to file a cause to address the third party's evaluation, recommendations and conclusions. On January 31, 2013,

OG&E filed a cause that included OG&E's response to the final evaluations and conclusions of the third party consultant, Black & Veatch, and OG&E's assessment of transportation and storage needs for the next three to five years.

Also, as part of this matter, on August 9, 2012, OG&E filed an application with the OCC requesting: (i) an order finding that a one-year extension to April 30, 2014 of OG&E's gas transportation and storage agreement with Enogex is prudent, (ii) a waiver of the OCC's competitive procurement rules and (iii) finding that the one-year extension of the gas transportation and storage agreement complies with the OCC's affiliate transaction rules. On September 14, 2012, OG&E filed a settlement agreement in which all parties to this matter agreed to the one-year extension of the Enogex contract and cost recovery from ratepayers at the rates currently in effect. On October 25, 2012, the OCC issued an order approving the settlement agreement.

**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
<b>Operating revenues</b>					
2012	\$840.7	\$855.0	\$1,113.4	\$862.1	\$3,671.2
2011	\$840.5	\$978.1	\$1,212.1	\$885.2	\$3,915.9
<b>Operating income</b>					
2012	\$ 98.3	\$177.3	\$ 304.0	\$ 97.3	\$ 676.9
2011	\$ 67.9	\$182.2	\$ 299.7	\$ 96.9	\$ 646.7
<b>Net income</b>					
2012	\$ 47.5	\$101.6	\$ 192.4	\$ 43.5	\$ 385.0
2011	\$ 29.7	\$109.3	\$ 181.4	\$ 43.2	\$ 363.6
<b>Net income attributable to OGE Energy</b>					
2012	\$ 37.1	\$ 93.9	\$ 185.5	\$ 38.5	\$ 355.0
2011	\$ 24.8	\$103.0	\$ 178.7	\$ 36.4	\$ 342.9
<b>Basic earnings per average common share attributable to OGE Energy common shareholders<sup>(A)</sup></b>					
2012	\$ 0.38	\$ 0.95	\$ 1.88	\$ 0.39	\$ 3.60
2011	\$ 0.25	\$ 1.05	\$ 1.82	\$ 0.37	\$ 3.50
<b>Diluted earnings per average common share attributable to OGE Energy common shareholders<sup>(A)</sup></b>					
2012	\$ 0.38	\$ 0.95	\$ 1.87	\$ 0.39	\$ 3.58
2011	\$ 0.25	\$ 1.04	\$ 1.80	\$ 0.37	\$ 3.45

<sup>(A)</sup> 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

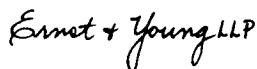
#### OGE Energy Corp.

We have audited the accompanying consolidated balance sheets and statements of capitalization of OGE Energy Corp. as of December 31, 2012 and 2011, and the related consolidated statements of income, comprehensive income, cash flows and changes in stockholders' equity for each of the three years in the period ended December 31, 2012. 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, 2012 and 2011, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2012, 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, 2012, 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 27, 2013 expressed an unqualified opinion thereon.



**Ernst & Young LLP**  
Oklahoma City, Oklahoma  
February 27, 2013

## 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.

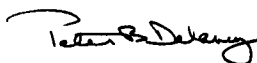
No change in the Company's internal control over financial reporting has occurred during the Company's most recently completed fiscal quarter that has materially affected, or is reasonably likely to materially affect, the Company's internal control over financial reporting (as such term is defined in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

## MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

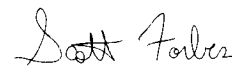
The management of the Company is responsible for establishing and maintaining adequate internal control over financial reporting. The Company's internal control system was designed to provide reasonable assurance to the Company's management and Board of Directors regarding the preparation and fair presentation 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, 2012. 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, 2012, 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 below.



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



**Scott Forbes**  
Controller and  
Chief Accounting Officer



**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, 2012, 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.

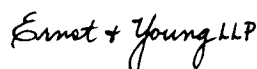
A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal 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, 2012, 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, 2012 and 2011, and the related consolidated statements of income, comprehensive income, cash flows and changes in stockholders' equity for each of the three years in the period ended December 31, 2012 of OGE Energy Corp. and our report dated February 27, 2013 expressed an unqualified opinion thereon.



**Ernst & Young LLP**  
Oklahoma City, Oklahoma  
February 27, 2013



## FINANCIAL PERFORMANCE

### OGE Energy Corp. Common Stock Data

	2012	2011	2010	2009	2008
Diluted earnings per share	\$ 3.58	\$ 3.45	\$ 2.99	\$ 2.66	\$ 2.49
Dividends paid per share <sup>(A)</sup>	\$ 1.57	\$ 1.50	\$ 1.45	\$ 1.42	\$ 1.39
Price range	\$60.21 – 50.23	\$57.17 – 40.56	\$46.18 – 33.87	\$37.79 – 19.70	\$36.23 – 19.56
Price/earnings ratio – year end	15.7	16.4	15.3	13.9	10.3
Return on equity – average	13.3%	14.9%	14.5%	13.1%	13.1%
Diluted average common shares outstanding (millions)	99.1	99.2	98.9	97.2	92.8

<sup>(A)</sup> Dividends were paid quarterly.

### Oklahoma Gas and Electric Company

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

	2012	2011	2010	2009	2008
Operating revenues	\$2,141	\$2,212	\$2,110	\$1,751	\$1,960
Gross margin on revenues	\$1,262	\$1,198	\$1,110	\$ 955	\$ 845
Operating income	\$ 489	\$ 472	\$ 414	\$ 354	\$ 278
Net income	\$ 280	\$ 263	\$ 216	\$ 200	\$ 143
Diluted earnings per share	\$ 2.83	\$ 2.65	\$ 2.18	\$ 2.06	\$ 1.54
Return on equity – average	10.9%	11.3%	10.3%	10.4%	9.3%
Total electricity sales (millions of megawatt hours)	29.4	29.5	28.1	26.9	28.2

### OGE Enogex Holdings LLC

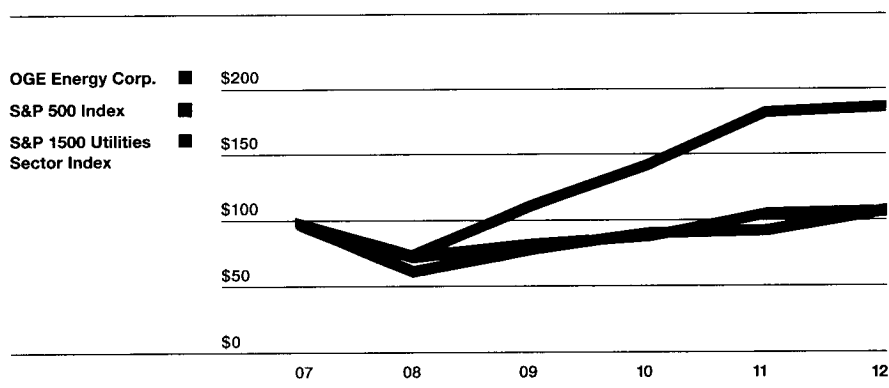
(In millions except EPS, before elimination of inter-segment items)

	2012	2011	2010	2009	2008
Operating revenues	\$1,609	\$1,787	\$1,708	\$1,205	\$2,239
Gross margin on revenues	\$ 489	\$ 441	\$ 423	\$ 358	\$ 408
Operating income	\$ 186	\$ 175	\$ 184	\$ 139	\$ 193
Net income	\$ 74	\$ 82	\$ 91	\$ 61	\$ 96
Diluted earnings per share	\$ 0.75	\$ 0.83	\$ 0.92	\$ 0.63	\$ 1.04
Return on equity – average	13.7%	17.9%	20.5%	13.2%	23.4%
Pipeline throughput (Tbtu/y) <sup>(A)</sup>	759	708	628	653	575

<sup>(A)</sup> 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, 2007, and that all dividends were reinvested. As of Dec. 31, 2012, the closing price of the Company's common stock on the New York Stock Exchange was \$56.31.



## HISTORICAL PERFORMANCE

(In millions except per share data)	2012	2011	2010	2009	2008
<b>Selected Financial Data</b>					
Operating revenues	\$3,671.2	\$3,915.9	\$3,716.9	\$2,869.7	\$4,070.7
Cost of goods sold	1,918.7	2,277.9	2,187.4	1,557.7	2,818.0
Gross margin on revenues	1,752.5	1,638.0	1,529.5	1,312.0	1,252.7
Other operating expenses	1,075.6	991.3	935.6	820.1	790.6
Operating income	676.9	646.7	593.9	491.9	462.1
Interest income	0.6	0.5	–	1.4	6.7
Allowance for equity funds used during construction	6.2	20.4	11.4	15.1	–
Other income	17.0	19.3	13.7	27.5	15.4
Other expense	16.5	21.7	17.9	16.3	25.6
Interest expense	164.1	140.9	139.7	137.4	120.0
Income tax expense	135.1	160.7	161.0	121.1	101.2
Net income	385.0	363.6	300.4	261.1	237.4
Less: net income attributable to noncontrolling interest	30.0	20.7	5.1	2.8	6.0
Net income attributable to OGE Energy	\$ 355.0	\$ 342.9	\$ 295.3	\$ 258.3	\$ 231.4
Diluted earnings per average common share	\$ 3.58	\$ 3.45	\$ 2.99	\$ 2.66	\$ 2.49
Long-term debt	\$2,848.6	\$2,737.1	\$2,362.9	\$2,088.9	\$2,161.8
Total assets	\$9,922.2	\$8,906.0	\$7,669.1	\$7,266.7	\$6,518.5
<b>Common Stock Statistics</b>					
Dividends paid per share	\$ 1.57	\$ 1.50	\$ 1.45	\$ 1.42	\$ 1.39
Dividends declared per share	\$ 1.5950	\$ 1.5175	\$ 1.4625	\$ 1.4275	\$ 1.3975
Book value	\$ 28.02	\$ 26.15	\$ 23.47	\$ 21.05	\$ 20.46
Market price – year end	\$ 56.31	\$ 56.71	\$ 45.54	\$ 36.89	\$ 25.78
Price/earnings ratio – year end	15.7	16.4	15.3	13.9	10.3
Basic average shares outstanding (millions)	98.6	97.9	97.3	96.2	92.4
Diluted average shares outstanding (millions)	99.1	99.2	98.9	97.2	92.8
Actual shares outstanding (millions)	98.7	98.1	97.6	97.0	93.5
Number of shareholders	18,905	19,948	20,942	21,971	22,705
<b>Capitalization Ratios<sup>(A)</sup></b>					
Stockholders' equity	51.9%	50.7%	50.4%	46.4%	47.0%
Long-term debt	48.1%	49.3%	49.6%	53.6%	53.0%
<b>Miscellaneous Statistics</b>					
Electric customers	798,110	789,146	782,558	776,550	770,088
Megawatt-hour sales (millions)	29.4	29.5	28.1	26.9	28.2
Megawatt generating capability – year end (thousands)	6.8	6.8	6.5	6.6	6.8
Megawatt peak demand (thousands)	7.0	7.1	6.6	6.4	6.5
Fuel mix (generation only, by kilowatt-hours generated)					
Natural gas	42%	39%	42%	38%	30%
Coal	52%	58%	55%	60%	68%
Wind	6%	3%	3%	2%	2%
Cost (in kilowatt-hours – cents)					
Natural gas	\$ 2.930	\$ 4.328	\$ 4.638	\$ 3.696	\$ 8.455
Coal	\$ 2.310	\$ 2.064	\$ 1.911	\$ 1.747	\$ 1.153
Weighted average	\$ 2.437	\$ 2.897	\$ 3.012	\$ 2.474	\$ 3.337
Total gas throughput volumes (TBtu/d) <sup>(B)</sup>	2.08	1.94	1.72	1.79	1.57
Total natural gas processed (TBtu/d)	0.98	0.79	0.82	0.70	0.66
Condensate sold (million gallons)	35	27	24	21	18
Average condensate sales price per gallon	\$ 1.95	\$ 2.09	\$ 1.81	\$ 1.36	\$ 2.28
Total natural gas liquids sold (million gallons)	867	685	688	493	426
Average natural gas liquids sales price per gallon	\$ 0.89	\$ 1.16	\$ 0.96	\$ 0.77	\$ 1.26
Average natural gas sales price per MMBtu <sup>(C)</sup>	\$ 2.79	\$ 4.08	\$ 4.24	\$ 3.37	\$ 7.23

<sup>(A)</sup> 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)].

<sup>(B)</sup> Trillion British thermal units per day.

<sup>(C)</sup> Million British thermal unit.

## INVESTOR INFORMATION

### Annual Meeting

The annual meeting of shareholders is scheduled for 10 a.m. Thursday, May 16, 2013, 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 29, 2013.

### 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 43006  
Providence, RI 02940-3006  
Phone toll free: 1-888-216-8114  
Internet account access:  
[www.computershare.com/investor](http://www.computershare.com/investor)

### 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](http://www.oge.com) or a prospectus and enrollment packet may be obtained by calling 1-888-216-8114. 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
<b>2013</b>		
First Quarter (through February 28)	\$61.39	\$55.39
<b>2012</b>		
First Quarter	\$57.54	\$51.24
Second Quarter	55.31	50.23
Third Quarter	56.49	50.60
Fourth Quarter	60.21	54.36
<b>2011</b>		
First Quarter	\$50.61	\$44.69
Second Quarter	53.50	47.64
Third Quarter	52.15	40.56
Fourth Quarter	57.17	45.70

The number of record holders of the Company's Common Stock at February 28, 2013, was 18,734. The reported closing market price of the Company's Common Stock on the New York Stock Exchange on February 28, 2013, was \$57.91.

### Dividend Direct Deposit

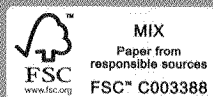
Shareholders may have their dividends deposited directly into their checking, savings or money market accounts. To take advantage of this service, please contact the registrar.

### 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](http://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.



OGE Energy Corp. employees are consistently generous contributors to the United Way. In 2012, our company's employees pledged \$827,182 to United Way campaigns in communities where they live and work.



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