OGE ENERGY CORP
Form DEF 14A
March 31, 2006

SCHEDULE 14A

SCHEDULE 14A INFORMATION

PROXY STATEMENT PURSUANT TO SECTION 14(A) OF THE SECURITIES EXCHANGE ACT OF 1934 (AMENDMENT NO.)

Filed by the Registrant [X]

Filed by a Party other than the Registrant [ ]

Check the appropriate box:

[ ] Preliminary Proxy Statement

[ ] Confidential, for Use of the Commission Only (as permitted by Rule 14a-6(e)(2))

[X] Definitive Proxy Statement

[ ] Definitive Additional Materials

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OGE ENERGY CORP.

(Name of Registrant as Specified In Its Charter)

(Name of Person(s) Filing Proxy Statement, if other than the Registrant)

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OGE Energy Corp.

Proxy Statement

and

Notice of Annual Meeting

May 18, 2006

Contents

	Page
Chairman s Letter	1
Notice of Annual Meeting of Shareowners	2
Proxy Statement	3
Proposal No. 1 Election of Directors	4
Proposal No. 2 Ratification of Ernst & Young LLP as Company s Principal Independent Accounts	12
Report of Audit Committee	13
Executive Officers Compensation	15
Report of Compensation Committee on Executive Compensation	15
Summary Compensation Table	19
Pension Plan Table	21
Employment Agreements and Change of Control Arrangements	23
Company Stock Performance	24
Security Ownership	25
Equity Compensation Plan Information	26
Section 16(a) Beneficial Ownership Reporting Compliance	26
Shareowner Proposals	26
Householding Information	27
Map	27
Annex A Audit Committee Charter	A-1
Appendix A 2005 Financial Statements and Management s Discussion and Analysis	

Notice of Annual Meeting
of Shareowners
and Proxy Statement

Thursday, May 18, 2006, at 10:00 a.m.

National Cowboy and Western Heritage Museum
1700 Northeast 63rd Street
Oklahoma City, Oklahoma

OGE Energy Corp.

March 31, 2006

Dear Shareowner:

You are cordially invited to attend the annual meeting of OGE Energy Corp. at 10:00 a.m. on Thursday, May 18, 2006, at the National Cowboy and Western Heritage Museum, 1700 Northeast 63rd Street, Oklahoma City, Oklahoma.

The matters to be voted on at the meeting are described in the Notice of Annual Meeting of Shareowners and Proxy Statement on the following pages.

Even though you may own only a few shares, your proxy is important in making up the total number of shares necessary to hold the meeting. Whether or not you plan to attend the meeting, please vote your shares as soon as possible. A return envelope for your proxy card is enclosed for your convenience. Again this year, in addition to telephone voting, you also have the option of voting by the Internet. Instructions are included on the proxy card. Your vote will be appreciated.

Those arriving before the meeting will have the opportunity to visit informally with the management of your Company. In addition to the business portion of the meeting, there will be reports on our current operations and outlook.

Your continued interest in the Company is most encouraging and, on behalf of the Board of Directors and employees, I want to express our gratitude for your confidence and support.

Very truly yours,

/s/ Steven E. Moore
Steven E. Moore
Chairman of the Board, President
and Chief Executive Officer

Notice of Annual Meeting

of Shareowners

The Annual Meeting of Shareowners of OGE Energy Corp. will be held on Thursday, May 18, 2006, at 10:00 a.m. at the National Cowboy and Western Heritage Museum, 1700 Northeast 63rd Street, Oklahoma City, Oklahoma, for the following purposes:

(1) To elect three directors to serve for a three-year term;

(2) To ratify the appointment of Ernst & Young LLP as our principal independent accountants; and

(3) To transact such other business as may properly come before the meeting.

The map on page 27 will assist you in locating the National Cowboy and Western Heritage Museum.

Shareowners who owned stock on March 21, 2006, are entitled to notice of and to vote at this meeting or any adjournment of the meeting. A list of such shareowners will be available, as required by law, at our principal offices at 321 North Harvey, Oklahoma City, Oklahoma 73102.

/s/ Carla D. Brockman
Carla D. Brockman
Vice President - Administration
and Corporate Secretary

Dated: March 31, 2006

IMPORTANT YOUR PROXY CARD IS ENCLOSED IN THIS ENVELOPE

To assure your representation at the meeting, please vote your shares by the Internet, by telephone or by signing, dating and returning the proxy card promptly in the enclosed envelope. No postage is required for mailing in the United States. If your shares are held in the name of a broker, trust, bank or other nominee and you plan to attend the meeting and vote your shares in person, you should bring with you a proxy or letter from the broker, trustee, bank or other nominee confirming your beneficial ownership of the shares.

2

Proxy Statement

March 31, 2006

Introduction

The Annual Meeting of Shareowners of OGE Energy Corp. (the Company) will be held at the National Cowboy and Western Heritage Museum, 1700 Northeast 63rd Street, Oklahoma City, Oklahoma, on May 18, 2006, at 10:00 a.m. For the convenience of those shareowners who may attend the meeting, a map is printed on page 27 that gives directions to the National Cowboy and Western Heritage Museum. At the meeting, it is intended that the first two items in the accompanying notice will be presented for action by the owners of the Company s Common Stock. The Board of Directors does not now know of any other matters to be presented at the meeting, but, if any other matters are properly presented to the meeting for action, the persons named in the accompanying proxy will vote upon them in accordance with their best judgment.

Your Board of Directors is sending you this proxy statement in connection with the solicitation of your proxy for use at the Annual Meeting. When you vote by Internet, by telephone or by mail, you appoint Steven E. Moore, H. H. Champlin and Robert Kelley as your representatives at the Annual Meeting. Mr. Moore, Mr. Champlin and Mr. Kelley will vote your shares, as you have instructed them, at the Annual Meeting. This way, your shares will be voted whether or not you attend the Annual Meeting. Even if you plan to attend the meeting, it is a good idea to vote your shares in advance of the meeting, just in case your plans change.

If an issue comes up for vote at the meeting that is not on the proxy card, Mr. Moore, Mr. Champlin and Mr. Kelley will vote your shares, under your proxy, in accordance with their best judgment.

Voting Procedures; Revocation of Proxy

You may vote by mail, by telephone, by Internet, or in person. To vote by mail, simply complete and sign the proxy card and mail it in the enclosed, prepaid and preaddressed envelope. If you mark your voting instructions on the proxy card, your shares will be voted as you instruct. If you return a signed card but do not provide voting instructions, your shares will be voted **FOR** the three named nominees for director and **FOR** the ratification of Ernst & Young LLP as the Company s principal independent accountants.

Shareowners of record also may vote by the Internet or by using the toll-free number listed on the proxy card. Telephone and Internet voting also is available to shareowners who hold their shares in the Automatic Dividend Reinvestment and Stock Purchase Plan (DRIP/DSPP) and the OGE Energy Corp. Employees Stock Ownership and Retirement Savings Plan (the Retirement Savings Plan). The telephone voting and Internet voting procedure is designed to verify shareowners through use of a number that is provided on each proxy card. This procedure allows you to vote your shares and to confirm that your instructions have been properly recorded. If you vote by telephone or by the Internet, you do not have to mail in your proxy card. Please see your proxy card for specific instructions.

If you wish to vote in person, we will pass out written ballots at the meeting. If you hold your shares in street name (i.e., they are held by your broker in an account for you), you must request a legal proxy from your broker in order to vote at the meeting.

If you change your mind after voting your proxy, you can revoke your proxy and change your vote at any time before the polls close at the meeting. You can revoke your proxy by either signing another proxy with a later date, by voting by Internet, by telephone or by voting at the meeting. Alternatively, you may provide a written statement to the Company (attention Carla D. Brockman, Vice President - Administration and Corporate Secretary) of your intention to revoke your proxy.

Record Date; Number of Votes

If you owned shares of our Common Stock at the close of business on March 21, 2006, you are entitled to one vote per share upon each matter presented at the meeting.

On March 1, 2006, there were 90,572,441 shares of Common Stock outstanding. The Company does not have any other outstanding class of voting stock. No person holds of record or, to our knowledge, beneficially owns more than 5% of our Common Stock.

Expenses of Proxy Solicitation

We will pay all costs associated with preparing, assembling and mailing the proxy cards and proxy statements. We also will reimburse brokers, nominees, fiduciaries and other custodians for their expenses in forwarding proxy materials to shareowners. Officers and other employees of the Company may solicit proxies by mail, personal interview, telephone, Internet and/or telegraph. In addition, we have retained Mellon Investor Services to assist in the solicitation of proxies, at a fee of approximately $7,500 plus associated costs and expenses. Our employees will not receive any additional compensation for soliciting proxies.

Mailing of Proxy Statement and Annual Report

This proxy statement and the enclosed proxy were mailed on or about March 31, 2006. Appendix A to this proxy statement includes our audited financial statements and management s discussion and analysis of financial condition and results of operations. This Appendix A, and our Summary Annual Report which contains Mr. Moore s letter to shareowners, condensed financial statements and a summary discussion of results of operations were mailed with this proxy statement on or about March 31, 2006, to all of our shareowners who owned stock on March 21, 2006.

Voting Under Plans

If you are a participant in our DRIP/DSPP, your proxy will represent the shares held on your behalf under the DRIP/DSPP and such shares will be voted in accordance with the instructions on your proxy. If you do not vote your proxy, your shares in the DRIP/DSPP will not be voted.

If you are a participant in our Retirement Savings Plan, you will receive a voting directive for shares allocated to your account. The trustee will vote these shares as instructed by you in your voting directive. If you do not return your voting directive, the trustee will vote your allocated shares in the same proportion that all plan shares are voted.

Voting of Shares Held in Street Name by

Your Broker

Brokerage firms have authority under New York Stock Exchange Rules to vote customers unvoted shares on certain routine matters, including the election of directors and ratification of the auditors. If you do not vote your proxy, your brokerage firm may either vote your shares on routine matters or leave your shares unvoted. We encourage you to provide instructions to your brokerage firm by voting your proxy. This ensures your shares will be voted at the meeting. When a brokerage firm votes its customers unvoted shares on routine matters, these shares are counted for purposes of establishing a quorum to conduct business at the meeting. A brokerage firm, however, cannot vote customers shares on non-routine matters. Accordingly, these shares (sometimes referred to as broker non-votes) are considered not entitled to vote on non-routine matters, rather than as a vote against the matter.

PROPOSAL NO. 1 -

ELECTION OF DIRECTORS

The Board of Directors of the Company presently consists of ten members. The directors are classified into three groups. One class of directors is elected at each year s Annual Meeting for a three-year term and to continue in office until their successors are elected and qualified. The following three persons are the nominees of the Board to be elected for such three-year term at the Annual Meeting to be held on May 18, 2006: Mr. John D. Groendyke, Mr. Robert O. Lorenz and Mr. Steven E. Moore. Each of these individuals is currently a director of the Company whose term as a director is scheduled to expire at the Annual Meeting. In addition, each of such individuals, as well as each other director of the Company during 2005, also was a director of the Company s principal subsidiary, Oklahoma Gas and Electric Company (OG&E).

Mr. William E. Durrett will retire from the Board effective at the Annual Meeting. Mr. Durrett has served as a director of OG&E, since 1991 and as a director of OGE Energy since its inception in 1996. The Board of Directors expresses its sincere appreciation and thanks to Mr. Durrett for his many years of contribution and dedicated service.

The enclosed proxy, unless otherwise specified, will be voted in favor of the election as directors of the previously listed three nominees. The Board of Directors does not know of any nominee who will be unable to serve, but if any of them should be unable to serve, the proxy holder may vote for a substitute nominee. No nominee or director owns more than 1.09% of any class of voting securities of the Company.

For the nominees described herein to be elected as directors, they must receive the affirmative vote of the holders of a majority of the votes of shares of Common Stock present in person or by proxy and entitled to vote. Withholding authority is treated as a vote against.

INFORMATION ABOUT DIRECTORS AND NOMINEES

The following contains certain information as of March 1, 2006, concerning the three nominees for directors, as well as the directors whose terms of office extend beyond the Annual Meeting on May 18, 2006.

Nominees for Election for Term Expiring at 2009 Annual Meeting of Shareowners

JOHN D. GROENDYKE, 61, is Chairman of the Board and Chief Executive Officer of Groendyke Transport Incorporated, a bulk truck transportation company in Enid, Oklahoma. Mr. Groendyke has worked at Groendyke Transport, Inc. since 1965. Mr. Groendyke also serves in various capacities at subsidiaries of Groendyke Transport, Inc., including Chairman of the Board and President of Bell Transport, Inc.; Oringderrf Tank Line, Inc.; Transport Company, Inc. and Triple A Transport and Chairman of the Board of GTI Insurance Co., Inc. and of James, Inc. Mr. Groendyke also serves as Director of Central Service Corp. and Central National Bank. Mr. Groendyke has been a director of the Company and of OG&E since January 2003 and is a member of the compensation committee and the nominating and corporate governance committee of the Board.

PHOTO

ROBERT O. LORENZ, 59, is a retired partner of the Arthur Anderson accounting firm. Mr. Lorenz joined Arthur Anderson in 1969, became a partner in 1982 and was named managing partner of the Oklahoma City office in 1994, the position he held until November 2002, when he retired. Mr. Lorenz serves on the Board of Directors and audit committees of Panhandle Royalty Company, Infinity Energy Resources, Inc., Kerr-McGee Corp. and is on the Board of Directors of the United Way of Central Oklahoma. The Board of Directors of the Company has determined that Mr. Lorenz s service on these other audit committees does not impair his ability to effectively serve on the Company s audit committee. Mr. Lorenz has been a director of the Company and OG&E since July 2005 and is a member of the audit committee and the nominating and corporate governance committee of the Board.

PHOTO

STEVEN E. MOORE, 59, is Chairman, President and Chief Executive Officer of the Company and of OG&E, having been appointed to such positions with the Company effective December 31, 1996. Mr. Moore was appointed President of OG&E in August 1995, and as Chief Executive Officer and Chairman of OG&E in May 1996. Mr. Moore has been employed by OG&E for more than 30 years, having previously served as Senior Vice President of Law and Public Affairs. He also serves as a director of INTEGRIS Health, is Chairman of the Board of Trustees of the OU Foundation, Inc. and has served on many industry-wide committees in the electric utility industry. Mr. Moore has been a director of the Company since 1996 and of OG&E since October 1995.

PHOTO

Directors Whose Terms Expire at 2008 Annual Meeting of Shareowners

HERBERT H. CHAMPLIN, 68, is President of Champlin Exploration, Inc., an independent oil producer, and Chairman of Enid Data Systems, computer marketers, both located in Enid, Oklahoma. Mr. Champlin also was engaged separately during 2005 as a part of his principal business occupation in the petroleum industry and had interests in oil and gas wells. Mr. Champlin has been a director of the Company since

PHOTO

December 31, 1996, and of OG&E since 1982, and is a member of the audit committee and the compensation committee of the Board.

LINDA PETREE LAMBERT, 66, is President of Lasso Corporation, a diversified oil and gas investment company, President of Enertree, L.L.C., also an oil and gas investment company, and a partner in Petree Valley Farms, a working farm in Verden, Oklahoma. Ms. Lambert also serves as a member of the Board of Directors of InvesTrust, a privately held trust company, the Oklahoma National Memorial Foundation and the United Way of Central Oklahoma. Ms. Lambert has been a director of the Company and of OG&E since November 2004, and is a member of the nominating and corporate governance committee of the Board.

PHOTO

RONALD H. WHITE, M.D., 69, is a practicing cardiologist and President, Partner and Director of Oklahoma Cardiovascular Associates, and a member of the Board of Managers of Oklahoma Heart Hospital. He was a member of the Board of Regents of the University of Oklahoma for 14 years. Presently Dr. White is a member of the Oklahoma State Regents for Higher Education. Dr. White has been a director of the Company since December 31, 1996, and of OG&E since 1989, and is a member of the compensation committee and the nominating and corporate governance committee of the Board.

PHOTO

Directors Whose Terms Expire at 2007 Annual Meeting of Shareowners

LUKE R. CORBETT, 59, is Chairman and Chief Executive Officer of Kerr-McGee Corporation, which is engaged in oil and gas exploration and production and chemical operations. He has been employed by Kerr-McGee Corporation for more than 17 years, having served as Chairman and Chief Executive Officer since 1997; President and Chief Operating Officer from 1995 to 1997; and Group Vice President from 1992 to 1995. Mr. Corbett also serves as a member of the Board of Directors of Noble Corporation. Mr. Corbett has been a director of the Company since December 31, 1996, and of OG&E since December 1, 1996. He serves as Lead Director of the Board, is chairman of the compensation committee and is a member of the audit committee of the Board.

PHOTO

ROBERT KELLEY, 60, is President of Kellco Investments Inc., a private investment company. Prior to May 1, 2001, he served as Chairman of the Board of Noble Affiliates, Inc., an independent energy company with exploration and production operations in the United States and international operations in China, Equador, Equatorial Guinea and the U.K. sector of the North Sea. Prior to October 2, 2000 he also served as President and Chief Executive Officer of Noble Affiliates, Inc. and of its three subsidiaries: Samedan Oil Corporation, Noble Gas Marketing, Inc. and Noble Trading, Inc. Mr. Kelley also serves as a member of the Board of Directors and audit committee of Lone Star Technologies, Inc., Cabot Oil and Gas Corporation and Smith International, Inc. The Board of Directors of the Company has determined that Mr. Kelley s service on these other audit committees does not impair his ability to effectively serve on the Company s audit committee. Mr. Kelley is a certified public accountant and his prior experiences include working for a public accounting firm and teaching accounting at two universities. Mr. Kelley has been a director of the Company since December 31, 1996, and of OG&E since January 17, 1996, and is chairman of the audit committee and is a member of the compensation committee of the Board.

PHOTO

J. D. WILLIAMS, 68, is founder and a former member of Williams & Jensen, P.C., a law firm in Washington, D. C., having resigned as a member of the firm in 1991 and having retired as an employee of the firm in December 2004. He has agreed to make himself available as an independent contractor to provide limited services to the firm through December 31, 2007. Mr. Williams is involved in various civic and related matters. Mr. Williams has been a director of the Company and of OG&E since January 2001, and is chairman of the nominating and corporate governance committee of the Board.

PHOTO

The affirmative vote of the holders of a majority of the shares of Common Stock present in person or by proxy and entitled to vote at the Annual Meeting will be required for the election of the three nominees as director. Withholding authority is treated as a vote against.

The Board of Directors recommends a vote FOR the election of the three nominees as director. Proxies solicited by the Board of Directors will be voted FOR the election of the three nominees as director, unless a different vote is specified.

INFORMATION CONCERNING THE BOARD OF DIRECTORS

Each member of our Board of Directors was also a director of OG&E during 2005. The Board of Directors of the Company met on seven occasions during 2005 and the Board of Directors of OG&E met on seven occasions during 2005. Each director attended at least 94% of the total number of meetings of the Boards of Directors and the committees of the Boards on which he or she served.

Committees. The standing committees of the Company s Board of Directors include a compensation committee, an audit committee and a nominating and corporate governance committee.

All members of these committees are independent, as independence is defined in the listing standards of the New York Stock Exchange. In addition, the Board has determined that Mr. Robert Kelley meets the Securities and Exchange Commission (SEC) definition of audit committee financial expert.

The members of the committees during 2005, the general functions of the committees and number of committee meetings in 2005 are set forth below.

Name of Committee and Members	General Functions of the Committee ****	Number of Meetings in 2005
Compensation Committee: Herbert H. Champlin Luke R. Corbett* Martha W. Griffin** John D. Groendyke Robert Kelley Ronald H. White, M.D.	Oversees compensation of directors and principal officers executive compensation policy benefit programs	6
Audit Committee: Herbert H. Champlin Luke R. Corbett William E. Durrett Robert Kelley* Robert O. Lorenz***	Oversees financial reporting process evaluate performance of independent auditors select independent auditors discuss with internal and independent auditors scope and plans for audits, adequacy and effectiveness of internal controls for financial reporting purposes, and results of their examinations review interim financial statements and annual financial statements to be included in Form 10-K	6
Nominating and Corporate Governance Committee: William E. Durrett Martha W. Griffin** John D. Groendyke Linda Petree Lambert Robert O. Lorenz*** Ronald H. White, M.D. J.D. Williams*	Reviews and recommends nominees for election as directors membership of director committees succession plans various corporate governance issues	5

* Chairperson
** Ms. Griffin retired from the Board May 19, 2005.
*** Mr. Lorenz joined the audit committee and the nominating and corporate governance committee of the Board September 21, 2005.
**** The specific duties for each committee are set forth in the charter of the committee, which, in the case of the audit committee, is attached as Annex A, and, in the case of the compensation committee and the nominating and corporate governance committee, is available on the OGE Energy web site at www.oge.com under the heading Investors, Corporate Governance.

8

Corporate Governance

The Board of Directors of the Company operates pursuant to a set of written Corporate Governance Guidelines that set forth the Company s corporate governance philosophy and the governance policies and practices that the Company has established to assist in governing the Company and its affiliates. The Guidelines state that the primary mission of the Board of Directors of the Company is to advance the interests of the Company s shareowners by creating a valuable long-term business.

The Guidelines describe Board membership criteria and the Board selection and member orientation process. The guidelines require that a majority of the directors must be independent and that members of each committee must be independent and state the Board s belief that the chief executive officer should be the only Company executive serving as a director. Absent approval of the Nominating and Corporate Governance Committee, no director may be nominated to a new term if he or she would be older than 70 at the time of election. The Guidelines also provide that no director may serve on more than three other boards of directors of publicly-held companies without the prior approval of the Nominating and Corporate Governance Committee. Directors whose professional responsibilities change, such as upon retirement or a change in employer, are required to submit a letter of resignation for the Board s consideration. The Guidelines provide that, except for employment arrangements with the chief executive officer, the Company will not engage in transactions with directors or their affiliates if such transactions would cast into doubt the independence of a director, present the appearance of a conflict of interest, or are otherwise prohibited by law, rule or regulation.

The Guidelines provide that the Compensation Committee of the Board will evaluate the performance of the chief executive officer on an annual basis and that the Nominating and Corporate Governance Committee will report to the Board at least annually on succession planning, which will include appropriate contingencies in the event the CEO retires or is incapacitated. The Guidelines also provide that the Nominating and Corporate Governance Committee is responsible for overseeing an annual assessment of the performance of the Board and Board committees, as well as for reviewing with the Board the results of these assessments. All of these tasks were completed in 2005.

The Guidelines provide that Board members have full access to officers and employees of the Company and, as necessary and appropriate, the Company s independent advisors, including legal counsel and independent accountants. The Guidelines further provide that the Board and each committee have the power to hire independent legal, financial or other advisors as they deem necessary. The Guidelines provide that the independent directors are to meet in executive session, generally coinciding with regularly scheduled Board meetings. In 2005, the independent directors met in executive session seven times.

Our Code of Conduct that is applicable to all of our directors, officers and employees, and the Corporate Governance Guidelines comply with the Sarbanes-Oxley Act of 2002 and the listing standards of the New York Stock Exchange. We also have a separate code of ethics that applies to our chief executive officer and our senior financial officers, including, our chief financial officer and our chief accounting officer, and that complies with the requirements imposed by the Sarbanes-Oxley Act of 2002 and the rules issued thereunder for codes of ethics applicable to such officers. The Board has reviewed and will continue to evaluate its role and responsibilities with respect to the legislative and other governance requirements of the New York Stock Exchange. All of our corporate governance materials, including our codes of conduct and ethics, our Guidelines for Corporate Governance and all of our committee charters, are available for public viewing on the OGE Energy web site at *www.oge.com* under the heading Investors, Corporate Governance. Copies of our corporate governance material also are available without charge to shareowners who request them. Requests must be in writing and sent to: Corporate Secretary, OGE Energy Corp., 321 North Harvey, P.O. Box 321, Oklahoma City, Oklahoma 73101-0321.

Director Independence. The Board of Directors of the Company is composed of ten directors, nine of whom are independent within the meaning of the New York Stock Exchange listing standards. Our Chairman and Chief Executive Officer is the only member of management serving as a director. For purposes of determining independence, we have adopted the following standards for director independence in compliance with the listing standards of the New York Stock Exchange:

A director who is or was an employee, or whose immediate family member is or was an executive officer of the Company or any of our subsidiaries is not independent until three years after the end of such employment relationship;

A director who received, or whose immediate family member received, more than $100,000 during any twelve-month period within the past three years in direct compensation from us or any of our subsidiaries, other than director and committee fees and pension or other forms or deferred compensation for prior service (provided such compensation is not contingent in any way on continued service), is not independent until three years after he or she ceases to receive more than $100,000 in any twelve-month period in such compensation;

9

A director who is a current partner or employee, or whose immediate family member is a current partner, of a firm that is the internal or external auditor of the Company or any of our subsidiaries is not independent;

A director who was, or whose immediate family member was, within the last three years (but is no longer) a partner or employee of the internal or external auditor of the Company or any of our subsidiaries and who personally worked on the audit of the Company or any of its subsidiaries within that time is not independent;

A director whose immediate family member is a current employee of the internal or external auditor of the Company or any of our subsidiaries and who participates in the firm s audit, assurance or tax compliance (but not tax planning) practice is not independent;

A director who is or was employed, or whose immediate family member is or was employed, as an executive officer of another company where, at the same time, any of our or any of our subsidiaries present executives is or was serving on that company s compensation committee is not independent until three years after the end of such service or the employment relationship;

A director who is a current employee, or whose immediate family member is a current executive officer, of a company that makes payments to, or receives payments from, us or any of our subsidiaries for property or services in an amount which, in any of the past three fiscal years, exceeds the greater of $1 million, or 2% of such other company s consolidated gross revenues, is not independent until three years after falling below such threshold; and

No director qualifies as independent unless the Board affirmatively determines that the director has no other relationship with us or any of our subsidiaries (either directly or as a partner, shareholder or officer of an organization that has a relationship with us or any of our subsidiaries) that in the opinion of the Board of Directors could be considered to affect the directors ability to exercise his or her independent judgement as a director.

The Board determined that each of the following members of the Board met the aforementioned independence standards: Herbert H. Champlin; Luke R. Corbett; William E. Durrett; John D. Groendyke; Robert Kelley; Linda Petree Lambert; Robert O. Lorenz; Ronald H. White, M.D. and J.D. Williams. Mr. Moore does not meet the aforementioned independence standards, because he is the current Chief Executive Officer and an employee of the Company.

Standing Committees. Our Board has three standing committees - audit; compensation; and nominating and corporate governance. All members of these committees are independent directors who are nominated and approved by the Board each year. The roles and responsibilities of these committees are defined in the committee charters adopted by the Board and provide for oversight of, among other things, executive management. The duties and responsibilities of the Board committees are reviewed regularly and are outlined above.

Lead Director. In an effort to strengthen independent oversight of management and to provide for more open communication, the Board has appointed Luke R. Corbett to serve in the role of lead director. The nonmanagement lead director chairs executive sessions of the Board conducted without management. These sessions will be held at least twice annually and were held seven times in 2005.

Communications with the Board of Directors. Shareowners who wish to communicate with members of the Board, including the independent directors individually or as a group, may send correspondence to them in care of the Corporate Secretary at the Company s principal offices, 321 North Harvey, P.O. Box 321, Oklahoma City, Oklahoma 73101-0321. We currently do not intend to have the Corporate Secretary screen this correspondence, but we may change this policy if directed by the Board due to the nature and volume of the correspondence.

The Company encourages each of its Board members to attend the Annual Meeting and the directors are expected to attend whenever reasonably possible. All nine of the Board members serving at the time attended the Annual Meeting in 2005.

Prohibition on Loans. The Company s Stock Incentive Plan has been amended to make it absolutely clear that all loans to executive officers are prohibited.

Auditors; Audit Partner Rotation. As described on page 12, the Company is requesting that the shareowners ratify the selection of Ernst & Young LLP as the Company s principal independent accountants for 2006. The Audit Committee charter provides that the audit partners will be rotated as required by Sarbanes-Oxley.

Stock Ownership Guidelines. During 2004, the Company established stock ownership guidelines for its directors and officers. The terms of these guidelines are explained on page 18 in the Report of the Compensation Committee on Executive Compensation.

Shareowner Nominations for Directors. It is expected that the nominating and corporate governance committee will consider nominees recommended by shareowners in accordance with our By-laws. Our By-laws provide that, if you intend to nominate director candidates for election at an

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Annual Meeting of Shareowners, you must deliver written notice to the Corporate Secretary no later than 90 days in advance of the meeting. The notice must set forth certain information concerning you and the nominee(s), including each nominee s name and address, a representation that you are entitled to vote at such meeting and intend to appear in person or by proxy at the meeting to nominate the person or persons specified in your notice, a description of all arrangements or understandings between you and each nominee and any other person pursuant to which the nomination or nominations are to be made by you, such other information as would be required to be included in a proxy statement soliciting proxies for the election of the nominee(s) and the consent of each nominee to serve as a director if so elected. The chairman of the Annual Meeting may refuse to acknowledge the nomination of any person not made in compliance with the foregoing procedure.

In considering individuals for nomination as directors, the nominating and corporate governance committee typically solicits recommendations from its current directors and is authorized to engage third party advisors, including search firms, to assist in the identification and evaluation of candidates. In 2005, the committee did not use any third party advisors to assist in the identification of potential candidates, but instead relied on an internal list compiled from recommendations of the committee and other members of the board.

The nominating and corporate governance committee has not established specific minimum qualities for director nominees or set forth specific qualities or skills that the nominating and corporate governance committee believes are necessary for one or more directors to possess. Instead, in evaluating potential candidates and incumbent directors for reelection, the nominating and corporate governance committee considers numerous factors, including judgment, skill, independence, integrity, experience with businesses and other organizations of comparable size, the interplay of the candidate s experience with the experience of other Board members, experience as an officer or director of another publicly-held corporation, understanding of management trends in general or in industries relevant to the Company, expertise in financial accounting and corporate finance, ability to bring diversity to the group, community or civic service, knowledge or expertise not currently on the Board, shareowner perception, and the extent to which the candidate would be a desirable addition to the Board and any committees of the Board. No particular weight is given to one factor over another on a general basis, but rather the factors are weighted in relationship to the perceived needs of the Board at the time of selecting nominees. The nominating and corporate governance committee will evaluate candidates recommended by shareowners on the same basis as they evaluate other candidates.

Following that process, in July 2005, the committee selected Mr. Robert O. Lorenz as the candidate that best suited our needs and recommended to the Board that he be elected as a director. Mr. Lorenz s election was approved by the Board for a term expiring at this Annual Meeting.

Director Compensation. Compensation of non-officer directors of the Company during 2005 consisted of an annual retainer fee of $75,000, of which $2,000 was payable monthly in cash (the same amount that has been paid monthly since August 1994) and $51,000 was deposited in the director s account under the Directors Deferred Compensation Plan (the Plan) in December 2005 and converted to 1,905.83 common stock units based on the closing price of the Company s Common Stock on November 30, 2005. The lead director and the chairman of the audit committee each received an additional $10,000 cash retainer. The chairmen of the compensation and nominating and corporate governance committees received an additional $5,000 annual cash retainer in 2005. In addition, all non-officer directors received $1,200 for each Board meeting and $1,200 for each committee meeting attended. These amounts represent the total fees paid to directors in their capacities as directors of the Company and OG&E. For 2006, the portion of the annual retainer which is to be payable in monthly installments in cash increased to $30,000. The fee for acting as lead director remained at $10,000, the additional annual retainer for acting as chairman of the audit committee remained at $10,000, and the additional annual retainer for acting as chairman of the compensation committee and the nominating and corporate governance committee remained at $5,000, with each of these additional amounts payable in November 2006. The fee for attendance at a Board or committee meeting remained at $1,200. The portion of the annual retainer to be deposited in the director s account and converted into common stock units under the Plan will be determined by the compensation committee at its meeting in November 2006.

Under the Plan, non-officer directors may defer payment of all or part of their attendance fees and the cash portion of their annual retainer fee, which deferred amounts are credited to their account on the date the deferred amounts otherwise would have been paid.

Amounts credited to the accounts are assumed to be invested in one or more of the investment options permitted under the Plan. During 2005, those investment options included a Company Common Stock fund, whose value was determined based on the stock price of the Company s Common Stock, a money market fund, a bond fund and several stock funds.

When an individual ceases to be a director of the Company, all amounts credited under the Plan are paid in cash in a lump sum or installments.

Historically, for those directors who retired from the Board of Directors after 10 years or more of service, the Company and OG&E continued to pay their annual cash retainer until their death. In November 1997, the Board eliminated this retirement policy for directors. Directors who retired prior to November 1997, however, will continue to receive benefits under the former policy.

PROPOSAL NO. 2

RATIFICATION OF THE APPOINTMENT OF ERNST & YOUNG LLP AS THE COMPANY S

PRINCIPAL INDEPENDENT ACCOUNTANTS FOR 2006

The Audit Committee of the Board of Directors has selected Ernst & Young LLP as principal independent accountants to audit the accounts of the Company for the fiscal year ending December 31, 2006. Ernst & Young LLP was originally selected by the Board, upon the recommendation of the Audit Committee, as principal independent accountants for the Company effective May 16, 2002.

While the Audit Committee is responsible for the appointment, retention, termination and oversight of the Company s principal independent accountants, the Audit Committee and the Board are requesting, as a matter of policy, that shareowners ratify the appointment of Ernst & Young LLP as the Company s principal independent accountants. The Audit Committee is not required to take any action as a result of the outcome of the vote on this proposal. However, if the shareowners do not ratify appointment, the Audit Committee may investigate the reasons for the shareowners rejection and may consider whether to retain Ernst & Young or to appoint another auditor. Furthermore, even if the appointment is ratified, the Audit Committee in its discretion may direct the appointment of different principal independent accountants at any time during the year if it determines that such a change would be in the best interests of the Company and its shareowners.

Representatives of Ernst & Young LLP will be present at the Annual Meeting and will have an opportunity to make a statement if they so desire. Such representatives will be available to respond to appropriate questions from the shareowners at the Annual Meeting.

The affirmative vote of the holders of a majority of the votes of shares of Common Stock present in person or by proxy and entitled to vote at the Annual Meeting will be required for the ratification of the appointment of Ernst & Young LLP as the Company s principal independent accountants for 2006. Abstentions from voting in this matter are treated as votes AGAINST.

The Board of Directors recommends a vote FOR the ratification of the appointment of the Company s principal independent accountants. Proxies solicited by the Board of Directors will be voted FOR the ratification of the appointment of the Company s principal independent accountants, unless a different vote is specified.

REPORT OF AUDIT COMMITTEE

The audit committee of the Board of Directors of the Company (the Audit Committee) oversees the Company s financial reporting process on behalf of the Board of Directors. Management, however, has the primary responsibility for the financial statements and the reporting process including the systems of internal controls.

The Audit Committee has five members, none of whom has any relationship to the Company that interferes with the exercise of his or her independence from management and the Company, and each of whom qualifies as independent under the standards used by the New York Stock Exchange, where the Company s shares are listed. The Audit Committee operates under a written charter that has been approved by the Board of Directors. A copy of the Audit Committee charter is attached as Annex A. The Audit Committee annually reviews and reassesses the adequacy of its charter. Among other things, the charter specifies the policies for selecting the auditors (including rotation for the audit partner) and the scope of the Audit Committee s responsibilities and how it carries out those responsibilities, including structure, processes and membership requirements.

In fulfilling its oversight responsibilities regarding the 2005 financial statements, the Audit Committee reviewed with Company management the audited financial statements contained in our Annual Report. The Audit Committee s review included a discussion of the quality, not just the acceptability, of the accounting principles, the reasonableness of significant judgments and the clarity of disclosures in the financial statements.

The Audit Committee also reviewed with the Company s independent auditors the Company s 2005 financial statements and management s assessment of the Company s internal control over financial reporting. The Company s independent auditors are responsible for expressing an opinion on the conformity of our audited financial statements with accounting principles generally accepted in the United States and on management s assessment of the Company s internal control over financial reporting. Our review with the independent auditors included a discussion of the auditors judgments as to the quality, not just the acceptability, of the Company s accounting principles and such other matters as are required to be discussed with the Audit Committee under Statement on Auditing Standards No. 61, as amended. In addition, the Audit Committee discussed with the independent auditors the auditors independence from management and the Company, including the matters in the written disclosures received by the Audit Committee pursuant to Rule 3600T of the Public Company Accounting Oversight Board.

The Audit Committee also discussed with the Company s internal and independent auditors the overall scope and plans for their respective audits for 2006. The Audit Committee meets with the internal and independent auditors, with and without management present, to discuss the results of their examinations, their evaluations of the Company s internal controls, and the overall quality of the Company s financial reporting. The Audit Committee held six meetings during 2005 and the Chairman of the Audit Committee conducted seven conferences with management by telephone or in person, to discuss Audit Committee matters.

Fees for Independent Auditors

Audit Fees

Total audit fees for 2005 were $2,107,307 for the Company s 2005 financial statement audit. These fees include $775,500 for the audit of internal control over financial reporting pursuant to the requirements of Sarbanes-Oxley section 404 and $37,321 for services in support of debt and stock offerings. Total audit fees for 2004 were $1,942,965 for the Company s 2004 financial statement audit. These fees include $923,125 for the audit of internal control over financial reporting pursuant to the requirements of Sarbanes-Oxley section 404 and $66,614 for services in support of debt and stock offerings.

The aggregate audit fees include fees billed for the audit of the Company s annual financial statements and for the reviews of the financial statements included in the Company s Quarterly Reports on Form 10-Q. For 2005, this amount includes estimated billings for the completion of the 2005 audit, which were rendered after year-end.

Audit-Related Fees

The aggregate fees billed for audit-related services for the fiscal year ended December 31, 2005 were $82,500, of which $67,500 was for employee benefit plan audits and $15,000 for other audit-related services.

The aggregate fees billed for audit-related services for the fiscal year ended December 31, 2004 were $103,870, of which $61,500 was for employee benefit plan audits and $42,370 for other audit-related services.

Tax Fees

The aggregate fees billed for tax services for the fiscal year ended December 31, 2005 were $292,096. These fees include $198,758 for tax preparation and compliance ($76,732 for the review of federal and state tax returns and $122,026 for assistance with examinations and other return issues) and $93,338 for other tax services.

The aggregate fees billed for tax services for the fiscal year ended December 31, 2004 were $840,995. These fees include $176,207 for tax preparation and

compliance ($74,882 for the review of federal and state tax returns and $101,325 for assistance with examinations and other return issues), $418,000 for tax assistance with the Oklahoma Investment Tax Credits, meals and entertainment project, Oklahoma sales and use tax, $181,248 for a change in our tax accounting method and $65,540 for other tax services.

All Other Fees

There were no other fees billed to the Company in 2005 or 2004 for other services.

The Audit Committee has considered whether the provision of non-audit services by the Company s principal independent public accountants is compatible with maintaining auditor independence.

In reliance on the review and discussions referred to above, the Audit Committee recommended to the Board of Directors, and the Board has approved, that the Company s audited financial statements be included in the Annual Report on Form 10-K for the fiscal year ended December 31, 2005, for filing with the SEC. The Audit Committee selected Ernst & Young LLP as the Company s independent public accountants for 2006. Representatives of Ernst & Young LLP will be present at the Annual Meeting of Shareowners and will have the opportunity to make a statement if they so desire. Such representatives will be available to respond to appropriate questions from shareowners at the meeting.

Audit Committee Pre-Approval Procedures

Rules adopted by the SEC in order to implement requirements of the Sarbanes-Oxley Act of 2002 require public company audit committees to pre-approve audit and non-audit services. Our Audit Committee follows procedures pursuant to which audit, audit-related and tax services, and all permissible non-audit services, are pre-approved by category of service. The fees are budgeted, and actual fees versus the budget are monitored throughout the year. During the year, circumstances may arise when it may become necessary to engage the independent public accountants for additional services not contemplated in the original pre-approval. In those instances, we will obtain the specific pre-approval of the Audit Committee before engaging the independent public accountants. The procedures require the Audit Committee to be informed of each service, and the procedures do not include any delegation of the Audit Committee s responsibilities to management. The Audit Committee may delegate pre-approval authority to one or more of its members. The member to whom such authority is delegated will report any pre-approval decisions to the Audit Committee at its next scheduled meeting.

For 2005, 100% of the audit-related fees, tax fees and all other fees were pre-approved by the Audit Committee or the Chairman of the Audit Committee pursuant to delegated authority.

Audit Committee

Robert Kelley, Chairman

Herbert H. Champlin, member

Luke R. Corbett, member

William E. Durrett, member

Robert O. Lorenz*

* Mr. Lorenz became a member of the Audit Committee on September 21, 2005. He joins in the report of the Audit Committee to the extent it covers the period for which he served on the Committee during 2005.

EXECUTIVE OFFICERS COMPENSATION

The Compensation Committee of the Board of Directors of the Company (the Committee) administers our executive compensation program. The Committee s report on compensation paid to executive officers during 2005 is set forth below.

REPORT OF COMPENSATION COMMITTEE ON EXECUTIVE COMPENSATION

General. The primary goals of the Committee in setting executive compensation in 2005 were: (i) to provide a competitive compensation package that would enable us to attract and retain key executives and (ii) to align the interests of our executives with those of our shareowners and also with our performance.

Compensation to our executive officers in 2005 was comprised primarily of salary, annual awards under our Annual Incentive Compensation Plan and long-term awards under our Stock Incentive Plan. In an effort to ensure the continued competitiveness of our executive compensation policies, the Committee followed its past practice and engaged Towers Perrin, a nationally recognized compensation consulting firm, to help survey the marketplace. In setting base salaries and making annual and long-term incentive awards, the Committee considered the compensation paid at the 50th percentile to executives with similar duties within the following three groups: (i) the 2004 Energy Services Industry Executive Compensation Database (the Energy Services Survey Group), consisting of approximately 98 energy services organizations, (ii) the 2004 General Industry Executive Compensation Database (the General Industry Survey Group), consisting of more than 850 companies in general industries and (iii) the average of the Energy Services Survey Group and the General Industry Survey Group (the Blended Industry Survey Group). All compensation data from these surveys was size-adjusted so that it would compare to the Company s or a subsidiary s projected 2006 revenues, as appropriate, and was updated using a 3.60 percent update factor to reflect anticipated 2006 compensation levels.

The Committee s intent in setting salaries is to pay competitive rates. The annual and long-term incentive portions of an executive s compensation are intended to achieve the Committee s goal of aligning an executive s interests with our shareowners and with our performance. These portions of an executive s compensation are placed at risk and are linked to the accomplishment of specific results that are designed to benefit our shareowners and the Company, both in the long and short term. As a result, during years of excellent performance, executives are provided the opportunity to earn a highly competitive level of compensation and, conversely, in years of below-average performance, their compensation may be below competitive levels. Generally, higher level executive officers have a greater level of their compensation placed at risk.

A Federal tax law currently limits our ability to deduct an executive s compensation in excess of $1,000,000 unless such compensation qualifies as performance based compensation or certain other exceptions are met. The Committee has continued to analyze the structure of its salary and various compensation programs in light of this law. The Committee s present intent is to take appropriate steps to ensure the continued deductibility of its executive compensation. For this reason, the Committee and the Board of Directors recommended, and the shareowners approved, the Stock Incentive Plan and the Annual Incentive Plan at the 2003 Annual Meeting so that certain compensation payable thereunder would qualify for the performance based compensation exception to the $1,000,000 deduction limit and thereby continue to be deductible by the Company.

Base Salary. The base salaries for our executive officers in 2005 were designed to be competitive with the Blended Industry Survey Group for most of our executive officers and with the Energy Services Survey Group for those officers serving only at our utility subsidiary, OG&E. Base salaries of our executive officers generally approximated the salary at the 50th percentile of the range for executives with similar duties in the appropriate survey group. Actual base salaries were determined based on individual performance and experience. The salaries of executive officers for 2005 were initially determined in November 2004, with an effective date of January 1, 2005, subject to change, if deemed appropriate by the Committee at its February 2005 meeting. Salaries were subject to adjustment during the year if an individual s duties and responsibilities changed or if deemed appropriate by the Committee. The 2005 base salary amounts for the most highly compensated executive officers are shown in the salary column of the Summary Compensation Table on page 19. For Mr. Hatfield and Mr. Harris, the amounts shown reflect increases in base salary approved by the Committee during 2005 from the initial levels set for these indi-

1 The companies in the Energy Services Survey Group, General Industry Survey Group and Blended Industry Survey Group are not the same as the companies in the S&P 500 Electric Utilities Index utilized in the Stock Performance Graph on page 24. The survey groups were selected by Towers Perrin, the Committee s compensation consultants, and, in the judgment of the Committee, are appropriate peer groups to consider for compensation purposes.

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viduals in November 2004. The increase for Mr. Harris was in response to his increase in responsibilities following his promotion in May 2005 to Senior Vice President of the Company and subsequent appointment as President of the Company s subsidiary, Enogex, Inc. For Mr. Hatfield, his increase was in response to his performance and to bring his salary to a level more competitive with other chief financial officers in the Blended Industry Survey Group with similar responsibilities.

Annual Incentive Compensation Plan. Awards with respect to 2005 performance were made under the Annual Incentive Compensation Plan to 80 employees, including all executive officers. The Plan was designed to provide key management personnel with annual incentive awards, the payment of which is tied to the achievement of specified Company objectives. Payouts of the award were in cash and were dependent entirely on the achievement of the corporate goals that were established by the Committee in February 2005.

For Messrs. Moore and Delaney, the two most senior executive officers of the Company, the corporate goals were based: (i) 50% on a Company consolidated earnings per share target established by the Committee (the Earnings Target), (ii) 25% on a combined operating and maintenance expense and capital expenditure target for the Company and OG&E established by the Committee (the O&M/Capital Target), and (iii) 25% on a consolidated net income target of Enogex and its subsidiaries (the Unregulated Income Target). At least two of these three corporate goals were used in establishing the corporate goals for all other executive officers. However, the weighting of the corporate goals was slightly different for the remaining executive officers based on their responsibilities. For four executive officers whose responsibilities pertain primarily or exclusively to OG&E, the corporate goals were based 50% on the Earnings Target and 50% on the O&M/Capital Target, and for Mr. Harris, whose responsibilities are focused on Enogex, his corporate goals were based 40% on the Earnings Target, 40% on the Unregulated Income Target and 20% on the return on invested capital of Enogex (the ROIC Target). For the remaining executive officers, the corporate goals were based 50% on the Earnings Target, 30% on the O&M/Capital Target and 20% on the Unregulated Income Target.

The amount of the award for each executive officer was expressed as a percentage of base salary (the targeted amount), with the officer having the ability, depending upon achievement of the corporate goals, to receive from 0% to 150% of such targeted amount. For 2005, the targeted amount ranged from 25% to 80% of base salary and approximated the 50^{th} percentile of the level of such awards granted to comparable executives in the Blended Industry Survey Group or, in the case of executive officers serving only at OG&E (our utility subsidiary), the Energy Services Survey Group.

The percentage of the targeted amount that an officer ultimately received based on corporate performance was subject to being decreased, but not increased, at the discretion of the Committee. For 2005, corporate performance of the Earnings Target, the ROIC Target and the Unregulated Income Target exceeded the minimum levels of achievement established by the Committee and, consequently, the Committee approved payouts under the Annual Incentive Plan to executive officers ranging from 19% to 79% of their base salaries and from approximately 75% to 129% of their targeted amounts. Corporate performance of the O&M/Capital Target did not exceed the minimum levels of achievement established by the Committee. Payouts under the Annual Incentive Plan are reflected in the bonus column of the Summary Compensation Table on page 19.

Long-Term Awards. Another significant component of executive compensation in 2005 was long-term awards under our Company s Stock Incentive Plan, which also was approved by the shareowners at the 2003 Annual Meeting. The Plan provides for the grant of any or all of the following types of awards: stock options, stock appreciation rights, restricted stock and performance units. In 2005, the Committee set a targeted amount of long-term compensation to be awarded each executive officer, which amount was expressed as a percentage of the individual s base salary as of January 1, 2005. In determining the target awards of long-term compensation, the Committee considered numerous factors as discussed below and reviewed the expected value of long-term compensation payable to executives in the 50^{th} percentile of the Energy Services Survey Group and the 50^{th} percentile of the Blended Industry Survey Group. The expected value of longterm compensation payable to the most senior level executives in the 50^{th} percentile of the Blended Industry Survey Group was substantially higher than the expected value of long-term compensation payable to comparable executives in the 50^{th} percentile of the Energy Services Survey Group and substantially higher than the expected value of long-term compensation awarded by the Committee in the past to comparable executive officers at the Company. While the Committee intends to continue to consider the long-term compensation payable to comparable executives in the 50^{th} percentile of the Blended Industry Survey Group in awarding long-term compensation to the Company s executive officers, the Committee s intent generally in 2005 was to provide executive officers with an aggregate value of long-term compensation equal to the expected value of long-term incentives payable to comparable executives in the 50^{th} percentile of the Energy Services Survey Group.

Historically, the Committee had awarded long-term compensation in the forms of stock options and restricted stock. At its meeting in the fourth quarter of 2002, the Committee chose to discontinue awarding restricted stock and, instead, to make awards of stock options and performance units commencing in 2003, with 50% of an executive officer s award being in the form of stock options and 50% in the form of performance units. For 2004, the Committee chose to place less emphasis on stock options with 25% of an executive officer s award of long-term compensation being in the form of stock options and 75% in the form of performance units. In 2005, the Committee decided to cease awarding stock options and instead awarded all long-term compensation in the form of performance units, with, as explained below, payout of the performance units is dependent on achieving specified performance criteria and hurdle rates. Specifically, payout of 75% of the performance units is dependent on the relative total shareholder return of the Company s common stock over the three-year period ending December 31, 2007 compared to a peer group and payout of the remaining 25% is dependent on the growth in the Company s earnings per share over the same three-year period compared to an earnings growth target (the Earnings Growth Target) set by the Committee.

The performance units were granted to executive officers during the first quarter of 2005. The number of performance units granted was determined by taking the amount of the executive s long-term compensation to be delivered in performance units (expressed as a percentage of the executive s base salary and as determined above) and dividing that amount by a recent closing price for the Company s Common Stock. This resulted in executives receiving a number of performance units with an expected value at the date of grant from 25% to 150% of their 2005 base salaries. The value of the performance units is substantially dependent upon the changing value of the Company s Common Stock in the marketplace. As indicated above, the terms of 75% of the performance units granted in 2005 to each executive officer entitle the officer to receive from 0% to 200% of the performance units granted based on the Company s total shareholder return over a three-year period (defined as share price increase plus dividends paid, divided by share price at beginning of the period) measured against the total shareholder return for such period (TSR) by a peer group selected by the Committee. The peer group for measuring the Company s TSR performance consists of approximately 80 utility holding companies and gas and electric utilities in the Standard & Poor s Utility Index. At the end of the three-year period (i.e., December 31, 2007), the terms of these performance units provide for payout of 100% of the performance units initially granted if the Company s TSR is at the 50^{th} percentile of the peer group, with higher payouts for performance above the 50^{th} percentile up to 200% of the performance units granted if the Company s TSR is at or above the 90^{th} percentile of the peer group. The terms of these performance units provide for payouts of less than 100% of the performance units granted if the Company s TSR is below the 50^{th} percentile of the peer group, with no payout for performance below the 35^{th} percentile.

For the remaining 25% of performance units granted in 2005 to each executive officer, the officer is entitled to receive from 0% to 200% of the performance units granted based on the growth in the Company s earnings per share from the $1.73 earned in 2004 over the three-year period ending December 31, 2007, measured against the Earnings Growth Target set by the Committee for such period. At the end of the three-year period (i.e., December 31, 2007), the terms of these performance units provide for payout of 100% of the performance units initially granted if the rate of growth of the Company s earnings per share during such period is at the Earnings Growth Target, with higher payouts for growth rates in excess of the Earnings Growth Target up to 200% for growth rates at or above 150% of the Earnings Growth Target and payout of less than 100% for growth rates below the Earnings Growth Target, with no payouts for growth rates below 62.5% of the Earnings Growth Target. All payouts of such performance units are made two-thirds in shares of the Company s common stock and one-third in cash.

In January 2003, executive officers received as part of their long-term compensation performance units based on TSR as described above for the three-year period ended December 31, 2005. The Company s TSR for such period was at the 66^{th} percentile (approximately the top one-third) of the peer group, which resulted in payouts in February 2006 of 139.5% of the performance units originally awarded in January 2003. The value of these payouts is reflected in the LTIP Payout column of the Summary Compensation Table on page 19.

CEO Compensation. The 2005 compensation for Mr. Moore consisted of the same components as the compensation for other executive officers. Mr. Moore s 2005 salary, which had remained unchanged since January 1, 2002 was increased from $710,000 to $750,000, and his 2005 targeted award under the Annual Incentive Plan, which also had remained unchanged since January 2002, was increased from 75% to 80% of his base salary, which the Compensation Committee believed were appropriate levels based on his performance and his prior experience. As a result of 2005 corporate performance of the corporate goals described above, he received a payout of $594,405 under the Annual Incentive Plan, representing approximately 79% of his base salary and 99% of his targeted award. Mr. Moore also received as long-term compensation in February 2005 an award of 47,301 perfor-

mance units, having an estimated value of 150% of his 2005 base salary. The terms of these performance units are identical to those awarded other executives and are described above. The award of performance units in 2005 made to Mr. Moore was based on his prior performance and a comparison of his award to the long-term compensation of other chief executive officers in the 50^{th} percentile of the Energy Services Survey Group. Consideration also was given by the Committee to Mr. Moore s prior experience with the Company and OG&E, his demonstrated leadership skills and his positive reputation within the community and utility industry.

Like other executive officers, Mr. Moore also received in February 2006 a payout of 139.5% of the performance units granted to Mr. Moore in January 2003 based on the Company s TSR for the three years ended December 31, 2005 being at the 66th percentile (approximately the top one-third) of the peer group selected by the Committee. The value of this award at the time of its payout was $1,207,041 and is reported in the LTIP Payout column of the Summary Compensation Table on page 19.

Other Benefits. Virtually all of our employees, including executive officers, are eligible to participate in the Retirement Savings Plan and pension plan. Both the Retirement Savings Plan and pension plan have supplemental restoration plans that enable executive officers to receive the same benefits that they would have received in the absence of limitations imposed by the federal tax laws on contributions or payouts. In addition, a Supplemental Executive Retirement Plan (the SERP), which was adopted in 1993, offers attractive pension benefits to lateral hires. Mr. Delaney is the only executive officer who participated in the SERP during 2005. The SERP is not expected to benefit other existing executive officers generally who remain employed by the Company or OG&E until age 65. In reviewing the benefits under the SERP, Retirement Savings Plan, pension plan and related restoration plans, the Committee sought in 2005 to provide participants with benefits at least commensurate with those offered by other utilities of comparable size. The restoration plans for the Retirement Savings Plan and pension plan contain provisions requiring their immediate funding in the event of certain mergers, consolidations or tender offers involving the Company.

Stock Ownership Guidelines. In an effort to further align management s interests with those of the shareowners, the Committee recommended, and the Board of Directors adopted, stock ownership guidelines for the officers of the Company and its subsidiaries during 2004. The Committee believes that linking a significant portion of an officer s current and potential future net worth to the Company s success, as reflected in the ownership of the Company s common stock and the price of the Company s common stock, helps to ensure that officers have a stake similar to that of the Company s shareowners. The share ownership guideline for each executive is based on the executive s position. The guideline for Chairman of the Board, President and Chief Executive Officer is five times base salary. The guidelines for other Company officers range from three and one-half to one and one-half times their base salaries. Each executive is expected to achieve the applicable ownership guideline within five years and the number of shares necessary to satisfy the guidelines is based on an assumed valuation of $25 per share. Similar guidelines were adopted for members of the Board of Directors at a level of five times their annual retainer.

Conclusion. The Committee believes that our Company s executive compensation system serves the interests of the Company and our shareowners effectively. The Committee takes very seriously its responsibilities with respect to our executive compensation system. To this end, the Committee will continue to monitor and revise the compensation policies as necessary to ensure that our compensation system continues to meet the needs of the Company and our shareowners.

Compensation Committee

Luke R. Corbett, Chairman

Herbert H. Champlin, member

Martha W. Griffin*

John D. Groendyke, member

Robert Kelley, member

Ronald H. White, M.D., member

* Ms. Griffin retired from the Board May 19, 2005.

SUMMARY COMPENSATION TABLE

The following table provides information regarding compensation paid or to be paid by us or any of our subsidiaries to the Chief Executive Officer and the five other most highly compensated executive officers for the past three years. To the extent the table shows zeros for other annual compensation or payouts under long-term incentive plans for a particular year, no amounts were required to be reported in such year or, in the case of other annual compensation, the amounts were below the threshold required for disclosure under the SEC s rules.

		Annual Compensation			Long-Term Compensation Awards		Payouts	
Name and Principal Position	Year	Salary ($)	Bonus(1) ($)	Other Annual Compensation(2) ($)	Restricted Stock Awards ($)	Securities Underlying Options/ SAR (#)	LTIP Payouts(3) ($)	All Other Compensation(4) ($)
S.E. Moore, Chairman,	2005	750,000	594,405	63,755	0	0	1,207,041	97,053
President and	2004	710,000	706,747	0	0	85,100	0	81,753
Chief Executive Officer	2003	710,000	772,817	0	0	202,300	0	48,558
P.B. Delaney	2005	475,000	329,399	0	0	0	586,208	56,135
Executive Vice	2004	440,000	350,387	0	0	44,000	0	43,192
President and Chief Operating Officer	2003	400,000	348,312	0	0	98,200	0	16,705
J.R. Hatfield	2005	328,125	154,636	0	0	0	308,912	31,927
Sr. Vice President and	2004	310,000	200,264	0	0	21,100	0	20,970
Chief Financial Officer	2003	310,000	221,932	0	0	51,800	0	28,151
J.T. Coffman(5)	2005	242,917	72,875	0	0	0	174,400	34,526
Former Sr. Vice	2004	260,000	120,064	0	0	13,500	0	24,547
President Power Supply	2003	255,000	143,065	0	0	30,100	0	26,701
D.P. Harris	2005	236,667	91,241	0	0	0	97,576	26,802
Senior Vice President	2004	190,000	78,683	0	0	6,800	0	26,205
Unregulated Business and President, Enogex, Inc.	2003	185,000	80,885	0	0	16,400	0	23,657
S.R. Gerdes	2005	219,583	49,406	0	0	0	93,760	32,007
Vice President	2004	220,000	77,220	0	0	9,700	0	25,234
Utility Operations	2003	200,000	85,909	0	0	15,700	0	29,386

(1) As explained on page 16, amounts in this column reflect payouts under the Annual Incentive Compensation Plan.

(2) Each of the executive officers receives certain personal benefits, including reimbursement for tax and estate planning, and club memberships. The value of these personal benefits received by each of the Named Executive Officers other than Mr. Moore is below the reporting threshold contained in the SEC s rules and, thus, is not included in this column. In addition to the personal benefits received by the other executive officers, Mr. Moore also was provided a Company-leased car for personal use and a corporate leased aircraft for travel to and from a medical institution for treatment. The use of the aircraft for this purpose was approved by the Compensation Committee. Mr. Moore reimbursed the Company for the amount that would have been included in his income under applicable Internal Revenue Code regulations, which amount for 2005 was approximately $34,109 less than the out-of pocket expenses to the Company.

(3) As explained on page 17, amounts in this column reflect payouts under the Stock Incentive Plan.

(4) Amounts in this column for 2005 reflect: (i) for Mr. Moore, $65,554 (Retirement Savings Plan and Deferred Compensation Plan) and $31,499 (insurance premiums); (ii) for Mr. Delaney, $49,523 (Retirement Savings Plan and Deferred Compensation Plan) and $6,612 (insurance premiums); (iii) for Mr. Hatfield, $15,855 (Retirement Savings Plan and Deferred Compensation Plan) and $16,072 (insurance premiums); (iv) for Mr. Coffman, $16,334 (Retirement Savings Plan and Deferred Compensation Plan) and $18,192 (insurance premiums); (v) for Mr. Harris, $9,460 (Retirement Savings Plan and Deferred Compensation Plan) and $17,342 (insurance premiums);

and (vi) for Mr. Gerdes, $13,356 (Retirement Savings Plan and Deferred Compensation Plan) and $18,651 (insurance premiums). A significant portion of the insurance premiums reported for each of these individuals is for life insurance policies and such premiums are recovered by the Company from the proceeds of the policies. Amounts shown as Retirement Savings Plan and Deferred Compensation Plan represent Company contributions for the individual under those plans.

(5) Mr. Coffman retired from the Company, effective December 1, 2005. See Employment Agreements and Change of Control Agreements for a summary of Mr. Coffman s consulting agreement with the Company after his retirement.

OPTIONS AND STOCK APPRECIATION RIGHTS (SARs)

The following table indicates for each of the named executives the number of exercisable and unexercisable options and SARs as of December 31, 2005.

Aggregated Option and SAR Exercises in 2005
and FY-End Option/SAR Value

(a) Name	(b) Shares Acquired on Exercise (#)	(c) Realized Value ($)	(d) Number of Unexercised Options and SARs at 12/31/05 (#) Exercisable (ex)/ Unexercisable (unex)		(e) Value of Unexercised In-the-Money Options and SARs at 12/31/05 ($) Exercisable (ex)/ Unexercisable (unex)*	
S.E. Moore	N/A	N/A	741,032	(ex)	$3,672,113	(ex)
			124,168	(unex)	$863,820	(unex)
P.B. Delaney	N/A	N/A	155,032	(ex)	$954,876	(ex)
			62,068	(unex)	$425,086	(unex)
J.R. Hatfield	130,200	$747,506	0	(ex)	$0	(ex)
			31,334	(unex)	$219,708	(unex)
J.T. Coffman	34,773	$286,267	78,194	(ex)	$271,156	(ex)
			0	(unex)	$0	(unex)
D.P. Harris	N/A	N/A	13,300	(ex)	$87,915	(ex)
			10,001	(unex)	$69,821	(unex)
S.R. Gerdes	18,466	$207,059	40,933	(ex)	$118,335	(ex)
			11,701	(unex)	$73,681	(unex)

* Share price on December 31, 2005 was $26.79. Options vest over three years with one-third becoming exercisable at the end of each year. Unexercisable options were granted on January 27, 2003 at a price of $16.685 and January 24, 2004 at a price of $23.575. No options or SARs were granted in 2005.

Long-Term Incentive Plans Awards In Last Fiscal Year

(a)	(b)	(c)	(d)	(e)	(f)
			Extimated future payouts under non-stock price-based plans		
Name	Number of shares, units or other rights (#)(1)	Performance or other period until maturation or payout(2)	Threshold (#)(2)	Target (#)(2)	Maximum (#)(2)
S.E. Moore	47,301	1/1/05-12/31/07	0	47,301	94,602
P.B. Delaney	26,961	1/1/05-12/31/07	0	26,961	53,922
J.R. Hatfield	11,920	1/1/05-12/31/07	0	11,920	23,840
J.T. Coffman	2,213	1/1/05-12/31/07	0	2,213	4,426
D.P. Harris	5,087	1/1/05-12/31/07	0	5,087	10,174
S.R. Gerdes	5,087	1/1/05-12/31/07	0	5,087	10,174

(1) Represents awards of performance units made under the Stock Incentive Plan. Each performance unit represents the value of one share of our common stock.

(2) The number of performance units ultimately received at the end of the performance cycle is based 75% on the Company s total shareholder return over a three-year period measured against the total shareholder return for such period by a peer group selected by the Committee, and 25% on the Company s earnings per share growth measured against target earnings per share growth. Following the end of the performance cycle, the performance units shown above will be paid out two-thirds in shares of our common stock and one-third in cash.

PENSION PLAN TABLE

The Company and OG&E maintain a qualified non-contributory pension plan (the Retirement Plan) generally covering all employees who have completed one year of service. Subject to limitations imposed by the Employee Retirement Income Security Act of 1974 (ERISA), benefits payable under the Retirement Plan are based upon (i) the average of the five highest consecutive years of cash compensation (which for the executives named in the Summary Compensation Table consists of salary and bonus) during an employee s last ten years prior to retirement and (ii) length of service. Social Security benefits are deducted in determining benefits payable under the Retirement Plan. Compensation covered by the Retirement Plan includes salaries, bonuses and overtime pay. Benefits are reduced for each year prior to age 62 that an employee retires. For an employee retiring prior to age 62, there is an alternative method of computing the reduction in benefits that is based on years of service and age with an employee whose age and years of service total or exceed 80 at the time of retirement receiving no reduction in the benefits payable under the plan. An employee may elect at time of retirement to receive, in lieu of an annuity, a lump-sum payment equal to the present value of the annuity. Also, for employees hired after January 31, 2000, the pension plan is a cash balance plan, under which the Company annually will contribute to the employee s account an amount equal to 5% of the employee s annual compensation plus accrued interest. Employees hired prior to February 1, 2000 receive the greater of the cash balance formula or final average compensation formula. Retirement benefits are payable to participants upon normal retirement (at or after age 65) or early retirement (at or after attaining age 55 and completing five or more years of service), to former employees after reaching retirement age (or, if elected, following termination) who have completed five or more years of service before terminating their employment and to participants after reaching retirement age upon total and permanent disability. As indicated above, the benefits payable under the Plan are subject to maximum limitations under ERISA. Should benefits for a participant at the time of retirement exceed the then permissible limits of ERISA, the Retirement Restoration Plan will provide benefits through a lump-sum distribution or in monthly installments actuarially equivalent to the amounts that would have been payable to such participant annually under the Retirement Plan but for the ERISA limits. The Company and OG&E fund the estimated benefits payable under the Retirement Restoration Plan through contributions to a trust for the benefit of those employees who will be entitled to receive payments under the Retirement Restoration Plan.

The following table sets forth the estimated annual benefits payable upon normal retirement under the Retirement Plan and Retirement Restoration Plan to persons in the compensation classification specified.

Average Compensation 5 Highest Years	Years of Service at Retirement 10	15	20	25	30	35	40	45
$ 125,000	$ 16,398	$ 24,597	$ 32,796	$ 40,995	$ 49,194	$ 57,393	$ 65,592	$ 73,791
150,000	20,148	30,222	40,296	50,370	60,444	70,518	80,592	90,666
175,000	23,898	35,847	47,796	59,745	71,694	83,643	95,592	107,541
200,000	27,648	41,472	55,296	69,120	82,944	96,768	110,592	124,416
225,000	31,398	47,097	62,796	78,495	94,194	109,893	125,592	141,291
250,000	35,148	52,722	70,296	87,870	105,444	123,018	140,592	158,166
300,000	42,648	63,972	85,296	106,620	127,944	149,268	170,592	191,916
350,000	50,148	75,222	100,296	125,370	150,444	175,518	200,592	225,666
400,000	57,648	86,472	115,296	144,120	172,944	201,768	230,592	259,416
450,000	65,148	97,722	130,296	162,870	195,444	228,018	260,592	293,166
500,000	72,648	108,972	145,296	181,620	217,944	254,268	290,592	326,916
600,000	87,648	131,472	175,296	219,120	262,944	306,768	350,592	394,416
700,000	102,648	153,972	205,296	256,620	307,944	359,268	410,592	461,916
800,000	117,648	176,472	235,296	294,120	352,944	411,768	470,592	529,416
900,000	132,648	198,972	265,296	331,620	397,944	464,268	530,592	596,916
1,000,000	147,648	221,472	295,296	369,120	442,944	516,768	590,592	664,416
1,100,000	162,648	243,972	325,296	406,620	487,944	569,268	650,592	731,916
1,200,000	177,648	266,472	355,296	444,120	532,944	621,768	710,592	799,416
1,300,000	192,648	288,972	385,296	481,620	577,944	674,268	770,592	866,916
1,400,000	207,648	311,472	415,296	519,120	622,944	726,768	830,592	934,416
1,500,000	222,648	333,972	445,296	556,620	667,944	779,268	890,592	1,001,916
1,600,000	237,648	356,472	475,296	594,120	712,944	831,768	950,592	1,069,416
1,700,000	252,648	378,972	505,296	631,620	757,944	884,268	1,010,592	1,136,916
1,800,000	267,648	401,472	535,296	669,120	802,944	936,768	1,070,592	1,204,416
1,900,000	282,648	423,972	565,296	706,620	847,944	989,268	1,130,592	1,271,916

As of December 31, 2005, the credited years of service for the individuals listed in the Summary Compensation Table on page 19 are as follows: S. E. Moore - 31 years; P. B. Delaney - 3 years; J. R. Hatfield - 11 years; J. T. Coffman 35 years; D. P. Harris - 9 years; and S. R. Gerdes - 27 years.

In 1993, OG&E adopted a SERP which is an unfunded supplemental plan that is not subject to the benefits limit imposed by ERISA. The plan generally provides for an annual retirement benefit at age 65 equal to 65% of the participant s average cash compensation during his or her final 36 months of employment, reduced by Social Security benefits, by amounts payable under the Retirement and Restoration Plans described above and by amounts received under pension plans from other employers. For a participant in the SERP who retires before age 65, the 65% benefit is reduced, with the reduction being 1% per year for ages 62 through 64, an additional 2% per year for ages 60 through 61, an additional 4% per year for ages 58 through 59 and an additional 6% per year for ages 55 through 57, so that a participant retiring at age 55 would receive 32% of his average cash compensation during his final 36 months, reduced by the deductions set forth above. Other than Mr. Delaney, no employee participated in the SERP during 2005.

EMPLOYMENT AGREEMENTS AND CHANGE OF CONTROL ARRANGEMENTS

The Company and OG&E have entered into employment agreements with each officer of the Company and OG&E that typically will become effective only upon a change of control of the Company. Under the agreements, the officer is to remain an employee for a three-year period following a change of control of the Company (the Employment Period). During the Employment Period, the officer is entitled to (i) an annual base salary in an amount at least equal to his or her base salary prior to the change of control, (ii) an annual bonus in an amount at least equal to his or her highest bonus in the three years prior to the change of control and (iii) continued participation in the incentive, savings retirement and welfare benefit plans. The officer also is entitled to payment of expenses and provision of fringe benefits to the extent paid or provided to (a) such officer prior to the change of control or (b) other peer executives of the Company. In addition, upon a change of control, Mr. Delaney will be considered vested under the SERP if he has not already attained age 55.

If, during the Employment Period, the officer s employment is terminated by the employer for reasons other than cause or disability or by such officer due to a change in employment responsibilities, the officer is entitled to the following payments: (i) all accrued and unpaid compensation and (ii) a severance payment equal to 2.99 times the sum of such officer s (a) annual base salary and (b) highest recent annual bonus. The officer also is entitled to continued welfare benefits for three years and outplacement services. If the payment of the foregoing benefits, when taken together with any other payments to the officer, would result in the imposition of the excise tax on excess parachute payments under Section 4999 of the Internal Revenue Code of 1986, as amended, then the severance benefits will be reduced if such reduction results in a greater after-tax payment to the officer. The officer is entitled to receive such amounts in a lump-sum payment within 30 days of termination. A change of control encompasses certain mergers and acquisitions, changes in Board membership and acquisition of securities of the Company.

Jack Coffman, former Senior Vice President of Power Supply for OG&E, entered into a consulting agreement with the Company, effective as of December 1, 2005. The term of the agreement extends to December 1, 2006, unless earlier terminated as provided therein. Under the terms of the agreement, Mr. Coffman agreed to consult and advise the Company and OG&E on specific matters designated by the chief executive officer (CEO) and chief operating officer (COO). In consideration for services provided under the agreement, Mr. Coffman will be paid $132.50 per hour, plus reasonable out-of-pocket expenses, for consulting services performed at the request of the CEO or COO. The $132.50 per hour represented Mr. Coffman s annual salary at the time of his retirement divided by 2,000 hours.

COMPANY STOCK PERFORMANCE

The following 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 500 Electric Utilities Index. The graph assumes that the value of the investment in the Company s Common Stock and each index was 100 at December 31, 2000, and that all dividends were reinvested. As of March 1, 2006, the closing price of the Company s Common Stock on the

New York Stock Exchange was $28.55.

GRAPH OMITTED

	2000	2001	2002	2003	2004	2005
OGE Energy Corp.	**100**	**100**	**82**	**120**	**139**	**148**
S&P 500 Index	**100**	**88**	**69**	**88**	**98**	**103**
S&P 500 Electric Utilities	**100**	**83**	**71**	**88**	**111**	**131**

24

SECURITY OWNERSHIP

The following table shows the number of shares of the Company s Common Stock beneficially owned on March 1, 2006, by each Director, by each of the Executive Officers named in the compensation table on page 19, and by all Executive Officers and Directors as a group:

	Number of Common Shares(1) (2) (3)		Number of Common Shares(1) (2) (3)
Herbert H. Champlin	56,535	S.E. Moore	984,853
Luke R. Corbett	38,066	P.B. Delaney	231,778
William E. Durrett	31,434	J.R. Hatfield	49,230
John D. Groendyke	32,965	J.T. Coffman	93,928
Robert Kelley	47,347	D.P. Harris	28,177
Linda Petree Lambert	3,655	S.R. Gerdes	61,307
Robert O. Lorenz	2,322	All Executive Officers and	
Ronald H. White, M.D.	43,975	Directors as a group	
J.D. Williams	26,107	(24 persons)	1,896,499

(1) Ownership by each executive officer is less than 1.09% of the class, by each director other than Mr. Moore is less than .06% of the class and, for all executive officers and directors as a group, is less than 2.09% of the class. Amounts shown include shares for which, in certain instances, an individual has disclaimed beneficial interest. Amounts shown for executive officers include 1,457,701 shares of Common Stock representing their interest in shares held under the Company s Retirement Savings Plan, Officer s Deferred Compensation Plan, and Stock Incentive Plan for which in certain instances they have voting power but not investment power.

(2) Amounts shown for Messrs. Champlin, Corbett, Durrett, Groendyke, Kelley, Lorenz, White and Williams and Ms. Lambert include, 48,788; 32,608; 21,974; 7,465; 30,247; 2,322; 36,875; 8,981 and 3,655 common stock units, respectively, under the Directors Deferred Compensation Plan.

(3) Includes shares subject to stock options granted under the Company s Stock Incentive Plan, exercisable within 60 days following March 1, 2006, as follows: each non-officer director except Mr. Groendyke, Mr. Lorenz and Ms. Lambert,

5,100 shares; Mr. Groendyke, Mr. Lorenz and Ms. Lambert, 0 shares; Mr. Moore, 836,833 shares; Mr. Delaney, 202,433 shares; Mr. Hatfield, 24,300 shares; Mr. Coffman, 78,194; Mr. Harris, 21,034 shares; and Mr. Gerdes, 49,400 shares.

The information on share ownership is based on information furnished to us by the individuals listed above and all shares listed are beneficially owned by the individuals or by members of their immediate family unless otherwise indicated.

25

EQUITY COMPENSATION PLAN INFORMATION

The following table provides certain information as of December 31, 2005 with respect to the shares of the Company s Common Stock that may be issued under the existing equity compensation plans:

Plan Category	A Number of Securities to be Issued upon Exercise of Outstanding Options	B Weighted Average Price of Outstanding Options	C Number of Securities Remaining Available for future issuances under equity compensation plans (excluding securities reflected in Column A
Equity Compensation Plans Approved by Shareowners (1)	2,139,376	$22.20	2,014,369(2)
Equity Compensation Plans Not Approved by Shareowners	0	N/A	N/A

(1) Consists of the OGE Energy Corp. Stock Incentive Plan, which was approved by shareowners at the 1998 annual meeting, and the OGE Energy Corp. 2003 Stock Incentive Plan, which was approved by shareowners at the 2003 annual meeting.

(2) Awards under the Stock Incentive Plan can take the form of stock options, stock appreciation rights, restricted stock or performance units.

SECTION 16(a) BENEFICIAL OWNERSHIP

REPORTING COMPLIANCE

Under federal securities laws, our directors and executive officers are required to report, within specified dates, their initial ownership in the Company s Common Stock and subsequent acquisitions, dispositions or other transfers of interest in such securities. We are required to disclose whether we have knowledge that any person required to file such a report may have failed to do so in a timely manner. Except as described in the following two sentences, to our knowledge, all of our officers and directors subject to such reporting obligations satisfied their reporting obligations in full in 2005. Messrs. Mel Perkins, Jack Coffman, Dan Harris and Paul Renfrow each failed to timely file one report on Form 4 relating to one transaction. The Form 4s were filed approximately one to four weeks late.

SHAREOWNER PROPOSALS

Any shareowner proposal intended to be included in the proxy statement for the Annual Meeting in 2007 must be received by the Company on or before December 1, 2006. Proposals received by that date, deemed to be proper for consideration at the Annual Meeting and otherwise conforming to the rules of the SEC, will be included in the 2007 proxy statement.

If you intend to submit a shareowner proposal for consideration at the Annual Meeting, but do not want it included in the proxy statement, you must follow the procedures established by our By-laws. These procedures require that you notify us in writing of your proposal. Your notice must be received by the Corporate Secretary at least 90 days prior to the meeting and must contain the following information:

- a brief description of the business you desire to bring before the Annual Meeting and your reasons for conducting such business at the Annual Meeting,
- your name and address,
- the number of shares of Common Stock which you beneficially own, and
- any material interest you may have in the business being proposed.

HOUSEHOLDING INFORMATION

We have adopted a procedure approved by the SEC called householding. Under this procedure, certain shareowners of record who have the same address and last name and do not participate in electronic delivery of proxy materials will receive only one copy of our Annual Report to Shareowners and proxy statement, unless one or more of these shareowners notifies us that they would like to continue to receive individual copies. This will reduce our printing costs and postage fees. Shareowners who participate in householding will continue to receive separate proxy cards. Also, householding will not in any way affect dividend check or dividend reinvestment statement mailings.

If you and other shareowners of record with whom you share an address currently receive multiple copies of our Summary Annual Report to Shareowners and/or proxy statement, or if you hold stock in more than one account, and in either case, you would like to receive only a single copy of the Annual Report to Shareowners or proxy statement for your household, please contact Mellon Investor Services; P.O. Box 3338, South Hackensack, NJ 07606 or phone toll free 1-888-216-8114.

If you participate in householding and would like to receive a separate copy of our Annual Report to Shareowners or this proxy statement, please call us at 405-553-3211 or write us at: OGE Energy Corp. Shareowner Relations, 321 North Harvey, P.O. Box 321, Oklahoma City, OK 73101-0321. We will deliver the requested documents to you promptly upon receipt of your request.

Some banks, brokers and other nominee record holders may be participating in the practice of householding proxy statements and annual reports. This means that only one copy of our proxy statement or Annual Report to Shareowners may have been sent to multiple shareowners in your household. We will promptly deliver a separate copy of either document to you if you call us at 405-553-3211 or write us at: OGE Energy Corp. Shareowner Relations, 321 North Harvey, P.O. Box 321, Oklahoma City, OK 73101-0321. If you want to receive separate copies of the Annual Report to Shareowners and proxy statement in the future, or if you are receiving multiple copies and would like to receive only one copy for your household, you should contact your bank, broker, or other nominee record holder.

LOCATION OF THE NATIONAL COWBOY AND WESTERN HERITAGE MUSEUM

East Bound or West Bound I-44

Exit to Martin Luther King Ave., continuing north approximately .2 miles.
Proceed west on Northeast 63rd Street .5 miles to National Cowboy
and Western Heritage Museum.

MAP OMITTED

Annex A

OGE ENERGY CORP.

AUDIT COMMITTEE CHARTER

Purposes

The purposes of the Audit Committee of the Board of Directors of OGE Energy Corp. (the Company) are to assist the Board of Directors in monitoring: (i) the integrity of the Company s financial statements, (ii) the Company s compliance with legal and regulatory requirements, (iii) the independent auditors qualifications and independence, and (iv) the performance of the independent auditors and the Company s internal audit function. The Committee also shall prepare the Committee s report, made pursuant to the Securities Exchange Act of 1934 (the Exchange Act), to be included in the Company s annual proxy statement (the Audit Committee Report).

Composition

Size. The size of the Committee shall be determined by the Board of Directors, but it always must have at least three members.

***Qualifications*.** Each Committee member shall have all of the following qualifications:

1) Each Committee member shall meet the independence criteria of (a) the rules of the New York Stock Exchange, Inc. (NYSE), as such requirements are interpreted by the Board of Directors in its business judgment, and (b) Section 301 of the Sarbanes-Oxley Act of 2002 and the rules and listing requirements promulgated thereunder by the Securities and Exchange Commission (SEC), including Rule 10A-3 under the Exchange Act, and the NYSE.

2) Each Committee member shall be financially literate or shall become financially literate within a reasonable period of time after his or her appointment to the Committee. Additionally, at least one member of the Committee shall have accounting or related financial management expertise sufficient to meet the criteria of a financial expert within the meaning of Section 407 of the Sarbanes-Oxley Act of 2002 and any rules promulgated thereunder by the SEC. The Board of Directors shall determine, in its business judgment, whether a member is financially literate and whether at least one member has the requisite accounting or financial management expertise and meets the financial expert criteria of Section 407 of the Sarbanes-Oxley Act of 2002 and any rules promulgated thereunder by the SEC. The designation or identification of a person as an audit committee financial expert shall not (a) impose on such person any duties, obligations or liability that are greater than the duties, obligations and liability imposed on such person as a member of the Audit Committee and Board of Directors in the absence of such designation or identification, or (b) affect the duties, obligations or liability of any other member of the Audit Committee or Board of Directors.

3) Each Committee member shall receive as compensation from the Company only those forms of compensation as are not prohibited by Section 301 of the Sarbanes-Oxley Act of 2002 and the rules and listing requirements promulgated thereunder by the SEC and the NYSE. Permitted compensation includes (a) director s fees (which includes all forms of compensation paid to directors of the Company for service as a director or member of a Board Committee) and/or (b) fixed amounts of compensation under a retirement plan (including deferred compensation) for prior service with the Company provided that such compensation is not contingent in any way on continued service. Additional directors fees may be paid to Audit Committee members to compensate them for the significant time and effort they expend in performing their duties as Audit Committee members.

4) If a Committee member simultaneously serves on the audit committee of more than three public companies (including the Company), the Board of Directors must determine that such simultaneous service would not impair the ability of such member to effectively serve on the Committee. The Company shall disclose any such determination in its annual proxy statement.

Selection. The Board of Directors will appoint the members and the Chair of the Committee. Each Committee member will serve at the pleasure of the Board and for such term as the Board may decide or until such Committee member is no longer a Board member. Committee members may be replaced by the Board at any time.

Duties and Responsibilities

The Committee is responsible for overseeing the Company s financial reporting process on behalf of the Board of Directors and preparing the Audit Committee Report. While the Audit Committee has the responsibilities and powers set forth in this Charter, it is not the duty of the Committee to plan or conduct audits or to determine that the Company s financial statements and disclosures are complete and accurate and are in accordance with generally accepted accounting principles and applicable rules and regulations. These are the responsibilities of management and the independent auditors.

The Committee is directly responsible for the appointment, termination, compensation, retention, evaluation and oversight of the work of the Company s independent auditors (including resolution of disagreements between management and the auditors regarding financial reporting) for the purpose of preparing or issuing an audit report or performing other audit, review or attest services for the Company.

In performing its responsibilities, the Committee shall:

1) Retain the Independent Auditors: The Committee has the sole authority to (a) directly appoint, retain, compensate, evaluate and terminate the Company s independent auditors, (b) approve all audit services (including the fees and terms thereof), (c) approve all internal-control related services (including the fees and terms thereof) and (d) approve any permitted non-audit services (including the fees and terms thereof). The Committee is to exercise this authority in a manner consistent with Sections 201, 202 and 301 of the Sarbanes-Oxley Act of 2002 and the rules and listing standards promulgated thereunder by the SEC and NYSE. The Committee may form and delegate authority to subcommittees consisting of one or more members when appropriate, including the authority to grant any pre-approvals of all audit and permitted non-audit services, provided that decisions of such subcommittee to grant pre-approvals shall be presented to the Committee at its next scheduled meeting. Prior to retaining the independent auditors, the Committee shall evaluate the auditors qualifications, performance and independence, which evaluation shall include, among other things, a review of the auditors prior work for the Company, consideration of the opinions of management and the internal auditors, and a review of the reports and other information described in paragraphs (2) and (3) below. The Committee shall report its conclusions with respect to the independent auditors to the Board. The Committee shall review and discuss with the independent auditors any documentation supplied by the auditors as to the nature and scope of any tax services to be approved, as well as the potential effects of the provision of such services on the auditors independence.

2) Review and Discuss the Auditors Quality Control: The Committee is to, at least annually, obtain and review a report by the independent auditors describing (a) the audit firm s internal quality control procedures, (b) any material issues raised by the most recent internal quality control review, or peer review, of the firm, or by any inquiry or investigation by governmental or professional authorities, within the preceding five years, respecting one or more independent audits carried out by the firm, and (c) any steps taken to deal with any such issues.

3) Review and Discuss the Independence of the Auditors: In connection with the retention of the Company s independent auditors, the Committee is to, at least annually, review and discuss the information and reports provided by management or the auditors relating to the independence of the audit firm, including, among other things, information related to the non-audit services provided and expected to be provided by the auditors and other relationships between the independent auditors and the Company. The Committee is responsible for (a) ensuring that the independent auditors submit at least annually to the Committee a formal written statement delineating all relationships between the auditors and the Company consistent with applicable independence standards, (b) engaging in a dialogue with the auditors with respect to any disclosed relationship or services that may impact the objectivity and independence of the auditors, and (c) taking

appropriate action in response to the auditors report to satisfy itself of the auditors independence. In connection with the Committee s evaluation of the independent auditors, the Committee shall review and evaluate the lead partner of the independent auditors and shall cause the regular rotation, to the extent required by Section 10(A)(j) of the Exchange Act, of the audit partners who serve on the Company s audit engagement team. The Committee also will consider whether, in order to assure continuing auditors independence, it is appropriate to adopt a policy of rotating the independent auditing firm on a regular basis.

4)

Set Hiring Policies: The Committee is to set hiring policies for employees or former employees of the independent auditors, which include the restrictions set forth in Section 206 of the Sarbanes-Oxley Act of 2002 and any rules promulgated thereunder by the SEC.

5) Review and Discuss the Audit Plan: The Committee is to review and discuss with the independent auditors the plans for, and the scope of, the annual audit and other examinations, including the adequacy of staffing and compensation.

6) Review and Discuss Conduct of the Audit: The Committee is to review and discuss with the independent auditors the matters required to be discussed by Statement on Auditing Standards No. 61, as amended by Statement on Auditing Standards No. 90, relating to the conduct of the audit, as well as any audit problems or difficulties the auditor encountered in the course of the audit work and management s response, including (a) any restriction on audit scope or the auditors activities or on access to requested information, (b) any disagreements with management, (c) significant issues discussed with the independent auditors national office and (d) whether the auditors have any reason to believe there has been conduct in violation of Rule 13b2-2 under the Exchange Act. The Committee is to decide all unresolved disagreements between management and the independent auditors regarding financial reporting.

7) Review and Discuss Financial Statements and Disclosures: The Committee is to review and discuss with appropriate officers of the Company and the independent auditors the annual audited and quarterly financial statements of the Company, including reviewing (a) the Company s specific disclosures under Management s Discussion and Analysis of Financial Condition and Results of Operations, and (b) the disclosures regarding internal controls and other matters required by Section 302 and 404 of the Sarbanes-Oxley Act of 2002 and any rules promulgated thereunder by the SEC. The Committee shall recommend to the Board whether the audited financial statements of the Company should be included in the Company s Form 10-K.

8) Review and Discuss Earnings Press Releases: The Committee is to review and discuss earnings and other financial press releases (including any use of pro forma or adjusted non-GAAP information), as well as financial information and earnings guidance provided to analysts and rating agencies (which review may occur after issuance and may be done generally as a review of the types of information to be disclosed and the form of presentation to be made).

9) Review and Discuss Internal Audit Plans and Senior Internal Auditing Executive: The Committee is to review and discuss with the senior internal auditing executive and appropriate members of the staff of the internal auditing department the plans for and the scope of their ongoing audit activities, including adequacy of staffing and compensation. The Committee also is to review the appointment and replacement of the senior internal auditing executive.

10) Review and Discuss Internal Audit Reports: The Committee is to review and discuss with the senior internal auditing executive and appropriate members of the staff of the internal auditing department the annual report of the audit activities, examinations and results thereof of the internal auditing department.

11) Review and Discuss the Systems of Internal Accounting Controls: The Committee is to review and discuss with the independent auditors, the senior internal auditing executive, the General Counsel and, if and to the extent deemed appropriate by the Chair of the Committee, members of their respective staffs the adequacy of the Company s internal accounting controls, the Company s financial, auditing and accounting organizations and personnel, and the Company s

policies and compliance procedures with respect to business practices, which shall include (a) by Sections 302 and 404 of the Sarbanes-Oxley Act of 2002 and any rules promulgated thereunder by the SEC, and (b) a review with the independent auditors of their attestation of management s assessment of internal controls over financial reporting and the independent auditors analysis of the adequacy of disclosures about changes in internal control over financial reporting.

12) Review and Discuss the Recommendations of Independent Auditors: The Committee is to review and discuss with the senior internal auditing executive and the appropriate members of the staff of the internal auditing department recommendations made by the independent auditors and the senior internal auditing executive, as well as such other matters, if any, as such persons or other officers of the Company may desire to bring to the attention of the Committee.

13) Review and Discuss the Audit Results: The Committee is to review and discuss with the independent auditors (A) the report of their annual audit, or proposed report of their annual audit, (B) the accompanying management letter, if any, (C) the reports of their reviews of the Company s interim financial statements conducted in accordance with Statement on Auditing Standards No. 100, and (D) the reports of the results of such other examinations outside of the course of the independent auditors normal audit procedures that the independent auditors may from time to time undertake. The foregoing shall include the reports required by Section 204 of the Sarbanes-Oxley Act of 2002 and any rules promulgated thereunder by the SEC and, as appropriate, a review of (a) major issues regarding (i) accounting principles and financial statement presentations, including any significant changes in the Company s selection or application of

accounting principles and (ii) the adequacy of the Company s internal controls and any special audit steps adopted in light of material control deficiencies, (b) analyses prepared by management and/or the independent auditors setting forth significant financial reporting issues and judgments made in connection with the preparation of the financial statements, including analyses of the effects of alternative GAAP methods on the financial statements, and (c) the effect of regulatory and accounting initiatives, as well as off-balance sheet structures, on the financial statements of the Company.

14) Obtain Assurances under Section 10A(b) of the Exchange Act: The Committee is to obtain assurance from the independent auditors that in the course of conducting the audit, there have been no acts detected or that have otherwise come to the attention of the audit firm that require disclosure to the Committee under Section 10A(b) of the Exchange Act.

15) Discuss Risk Management Policies: The Committee is to discuss with management the Company s major financial risk exposures and the steps management has taken to monitor and control the exposures, including the Company s risk assessment and risk management policies and guidelines.

16) Obtain Reports Regarding Conformity With Legal Requirements and the Company s Code of Business Conduct and Ethics: The Committee is to periodically obtain reports from management, the Company s senior internal auditing executive and the independent auditor that the Company and its affiliated entities are in conformity with applicable legal requirements and the Company s Code of Ethics (including the Code of Ethics for CEO and Senior Financial Officers). The Committee is to review and discuss reports of insider and affiliated party transactions. The Committee should advise the Board with respect to the Company s policies and procedures regarding compliance with applicable laws and regulations and with the Company s Code of Ethics (including the Code of Ethics for CEO and Senior Financial Officers).

17) Establish Procedures for Complaints Regarding Financial Statements or Accounting Policies: The Committee is to establish procedures for (A) the receipt, retention, and treatment of complaints received by the Company from employees regarding accounting, internal accounting controls, or auditing matters; and (B) the confidential, anonymous submission by employees of the Company of concerns regarding questionable accounting or auditing matters as required by Section 301 of the Sarbanes-Oxley Act of 2002 and the rules and listing requirements promulgated thereunder by the SEC and the NYSE. The Committee is to discuss with management and the independent auditors any correspondence with regulators or governmental agencies and any complaints or

concerns regarding the Company s financial statements or accounting policies.

18) Discuss With General Counsel Matters Regarding Financial Statements or Compliance Policies: The Committee should discuss with the Company s General Counsel legal matters that may have a material impact on the financial statements or the Company s compliance policies.

19) Review and Discuss Other Matters: The Committee should review and discuss such other matters that relate to the accounting, auditing and financial reporting practices and procedures of the Company as the Committee may, in its own discretion, deem desirable in connection with the review functions described above.

20) Make Board Reports: The Committee should report its activities regularly to the Board of Directors in such manner and at such times as the Committee and the Board of Directors deem appropriate, but in no event less than once a year. Such report should include the Committee s conclusions with respect to its assessment of the performance and independence of the independent auditors.

21) Maintain Flexibility: The Committee, in carrying out its responsibilities, policies and procedures should remain flexible, in order to best react to changing conditions and circumstances.

Meetings

The Committee shall meet in person or telephonically at least quarterly, or more frequently as it may determine necessary, to comply with its responsibilities as set forth herein. The Chair of the Committee will, in consultation with the other members of the Committee, the Company s independent auditors and the appropriate officers of the Company, establish the agenda for each Committee meeting. Any Committee member may submit items to be included on the agenda. Committee members may also raise subjects that are not on the agenda at any meeting. The Committee Chair or a majority of the Committee members may call a meeting of the Committee at any time. A majority of the number of Committee members selected by the Board will constitute a quorum for conducting business at a meeting of the Committee. The act of a majority of Committee members present at a Committee meeting at which quorum is in attendance will be the act of the Committee, unless a greater number is required by law, the Company s certificate of incorporation or its by-laws. Any Committee member may be excused from a meeting to permit the remaining members of the Committee to act on any matter in which such member s participation is not appropriate, and such member s absence shall not destroy the quorum for the meeting. The Committee also may take action by unanimous written consent. The Committee Chair will supervise the conduct of the meetings and will have other responsibilities as the Committee may specify from time to time.

The Committee may request any officer or employee of the Company or any representative of the Company s legal counsel or independent auditors or other advisors to attend a meeting of the Committee or to meet with any members, or representatives of the Committee. The Committee shall meet with the Company s management, the internal auditors and the independent auditors periodically in separate private sessions to discuss any matter that the Committee, management, the independent auditors or such other persons believe should be discussed privately.

Resources and Authority

The Committee shall have appropriate resources and authority to discharge its responsibilities as required by law, including the authority to engage independent legal counsel and other advisors as the Committee deems necessary to carry out its responsibilities. The Committee may also, to the extent it deems necessary or appropriate, meet with the Company s investment bankers or financial analysts who follow the Company.

The Company will provide for appropriate funding, as determined by the Committee, for payment of compensation (i) to the Company s independent auditors engaged for the purpose of rendering or issuing an audit report or related work or performing other audit, review or attest services for the Company, and (ii) to independent counsel or any other advisors employed by the Committee.

Audit Committee Report

The Committee will prepare, with the assistance of management, the independent auditors and legal counsel, the Audit Committee Report.

Annual Review

In 2004 and annually thereafter, the Committee shall (a) review this Charter with the Board and recommend any changes to the Board and (b) evaluate its performance against the requirements of this Charter and review this evaluation with the Board. The Committee shall conduct its review and evaluation in such manner as the Committee, in its business judgment, deems appropriate.

Consistent with New York Stock Exchange listing requirements, this Charter will be included on the Company s website and will be made available upon request sent to the Company s Corporate Secretary. The Company s annual report to stockholders will state that this Charter is available on the Company s website and will be available upon request sent to the Company s Corporate Secretary.

February 2006

A-6

OGE Energy Corp.

2005 Management s
Discussion and Analysis

Appendix A to the Proxy Statement

Management s Discussion and Analysis of Financial Condition and Results of Operations.

Introduction

OGE Energy Corp. (collectively, with its subsidiaries, 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 two business segments, the Electric Utility and the Natural Gas Pipeline segments.

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, is the largest electric utility in Oklahoma and its franchised service territory includes the Fort Smith, Arkansas area. OG&E sold its retail gas business in 1928 and is no longer engaged in the gas distribution business.

The operations of the Natural Gas Pipeline segment are conducted through Enogex Inc. and its subsidiaries (Enogex) and consist of three related businesses: (i) the transportation and storage of natural gas, (ii) the gathering and processing of natural gas and (iii) the marketing of natural gas. The vast majority of Enogex s natural gas gathering, processing, transportation and storage assets are located in the major gas producing basins of Oklahoma. In October 2005, Enogex sold its interest in Enogex Arkansas Pipeline Corporation (EAPC), through which it had held a controlling interest in Ozark Gas Transmission, L.L.C. (OGT), a FERC regulated interstate pipeline that extends from southeast Oklahoma through Arkansas to southeast Missouri. The Company received approximately $177.4 million cash proceeds and recognized an after tax gain of approximately $36.7 million from the sale of this business in the fourth quarter. Enogex used approximately $31.9 million of the proceeds to repay principal and accrued interest on long-term debt and approximately $46.7 million to pay taxes associated with EAPC. The balance of the proceeds of approximately $98.8 million will be used to invest, over time, in strategic assets to diversify its asset base. Also, during the third quarter of 2005, Enogex Compression Company, LLC (Enogex Compression) sold it majority interest in Enerven Compression Services, LLC (Enerven), a joint venture focused on the rental of natural gas compression assets. The EAPC and Enerven businesses have been reported as discontinued operations in the Company s Consolidated Financial Statements and are discussed further in Note 4 of Notes to Consolidated Financial Statements.

Executive Overview

The Company s vision is to be a regional energy company focused on its regulated utility business and natural gas pipeline business that is recognized for operational excellence and financial performance. As explained below, the Company intends to maintain the majority of its assets in the regulated utility business complemented by its natural gas pipeline business. The Company s long-term financial goals include earnings growth of four to five percent on a weather-normalized basis, an annual total return in the top third of its peer group, dividend growth and maintenance of strong credit ratings.

OG&E has been focused on its Customer Savings and Reliability Plan, which provides for increased investment at the utility to improve reliability and meet load growth, replace infrastructure equipment and deploy newer technology that improves operational and environmental performance. As part of this plan, OG&E purchased a 77 percent interest in the 520 megawatt (MW) natural gas-fired combined cycle NRG McClain Station (the McClain Plant) in July 2004. Capacity payment savings from reduced cogeneration payments and fuel savings from the McClain Plant will be utilized to help mitigate the price increases associated with these investments. In 2005 OG&E filed a rate case to recover, among other things, its investment in, and the operating expenses of, the McClain Plant. An order was issued by the OCC on December 12, 2005 providing for a rate increase of approximately $42.3 million and OG&E implemented the new electric rates in January 2006. For additional information regarding the McClain Plant acquisition, the new electric rates and related regulatory matters, see Note 15 of Notes to Consolidated Financial Statements.

Enogex plans to continue to implement improvements to enhance long-term financial performance of its mid-continent assets through more efficient operations and effective commercial management of the assets. In addition, Enogex is seeking to diversify its gathering, processing and transportation businesses principally by expanding into other geographic areas that are complementary with the Company s strategic capabilities. Enogex s marketing business, which concentrates principally on origination of physical sales of natural gas, has expanded into the Gulf Coast and Rocky Mountain markets. Also, in 2005, Enogex s marketing business implemented a refocused strategy that seeks to minimize the amount of capital employed and to complement better the natural gas pipeline business. Enogex s improved financial performance and increased flexibility from the reduction of its long-term debt has enabled Enogex to begin to contribute to funding the

Company s dividend. As discussed above, during 2005, Enogex sold its interests in EAPC and Enerven and will continue to review its asset portfolio and seek to divest underperforming or non-strategic assets.

The Company s business strategy is to continue maintaining the diversified asset position of OG&E and Enogex so as to provide competitive energy products and services to customers primarily in the south central United States. The Company will focus on those products and services with limited or manageable commodity exposure. The Company intends for OG&E to continue as a vertically integrated utility engaged in the generation, transmission and distribution of electricity and to represent over time approximately 70 percent of the Company s consolidated assets. The remainder of the Company s consolidated assets will be in Enogex s businesses. At December 31, 2005, OG&E and Enogex represented approximately 66 percent and 32 percent, respectively, of the Company s consolidated assets. The remaining two percent of the Company s consolidated assets were primarily at the holding company. In addition to the incremental growth opportunities that Enogex provides, the Company believes that many of the risk management practices, commercial skills and market information available from Enogex provide value to all of the Company s businesses subject to the evolving federal regulations of the FERC in regard to the operations of the wholesale power market. In addition, Oklahoma and Arkansas legislatures and utility commissions may propose changes from time to time that could subject utilities to market risk. Accordingly, the Company is applying risk management practices to all of its operations in an effort to mitigate the potential adverse effect of any future regulatory changes.

OG&E has approximately 430 MW s of contracts with qualified cogeneration facilities (QF) and small power production producers (QF contracts) that will expire at the end of 2007, unless extended by OG&E. In addition, effective September 1, 2004, OG&E entered into a new 15-year power sales agreement for 120 MW s with PowerSmith Cogeneration Project, L.P. OG&E will continue reviewing all of the supply alternatives to these expiring 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. Accordingly, OG&E will continue to explore opportunities to build or buy power plants in order to serve its native load. As a result of the high volatility of current natural gas prices and the increase in natural gas prices, OG&E will also assess the feasibility of constructing additional base load coal-fired units as well as wind generation facilities.

Enogex initiated a program in 2002 to improve its financial profile and performance. Since January 1, 2002, Enogex has completed significant sales transactions, reduced debt, reduced its number of employees, reorganized its operations and restructured its senior management team. In addition to focusing on growing its earnings, Enogex managed its commodity price and earnings volatility exposures and minimized its exposure to keep-whole processing arrangements. Enogex s profitability increased significantly from 2003 to 2005 due to the performance improvement plan initiated in 2002 as well as an overall favorable business environment coupled with higher commodity prices. While the Company believes substantial progress has been achieved, additional opportunities remain. Enogex continues to review its work processes, evaluate the rationalization of assets, negotiate better terms for both new contracts and replacement contracts, manage costs and pursue opportunities for organic growth, all in an effort to further improve its cash flow and net income.

In 2006, the Company expects to continue to focus on improving operational efficiencies and profitable growth at OG&E and redeploying capital in expansion projects at Enogex. Across all business units, the Company continues to pursue a disciplined approach to continuous improvement and continues to improve efficiency of operations in enterprise-wide services to operate business units at reduced costs.

On September 30, 2005, the Company and OG&E entered into revolving credit agreements totaling $750 million. These agreements include two separate facilities, one for the Company in an amount up to $600 million and one for OG&E in an amount up to $150 million. Each of the credit facilities has a five-year term with two options to extend the term for one year. These revolving credit agreements will provide sufficient liquidity to meet the Company s daily operational needs, capital improvements at OG&E and expansion projects at Enogex.

Forward-Looking Statements

Except for the historical statements contained herein, the matters discussed in the following discussion and analysis, including the discussion in 2006 Outlook , 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 , p project and similar expressions. Actual results may vary materially. Factors that could cause actual results to differ materially include, but are not limited to: general economic conditions, including the availability of credit, actions of rating agencies and their impact on capital expenditures; the Company s ability and the ability of its subsidiaries to obtain financing on favorable terms; prices of electricity, coal, natural gas and natural gas liquids, each on a stand-alone basis and in relation to each other; business conditions in the energy industry; competitive factors including the extent and timing of the entry of additional competition in

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the markets served by the Company; unusual weather; availability and prices of raw materials; 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; 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 including Risk Factors to the Company s Form 10-K for the year ended December 31, 2005.

Overview

Summary of Operating Results

2005 compared to 2004. The Company reported net income of approximately $211.0 million, or $2.32 per diluted share, as compared to approximately $153.5 million, or $1.73 per diluted share, for the years ended December 31, 2005 and 2004, respectively. The increase in net income during 2005 as compared to 2004 was primarily due to:

OG&E reported net income of approximately $129.7 million, or $1.43 per diluted share of the Company s common stock, as compared to approximately $107.6 million, or $1.22 per diluted share, during 2005 and 2004, respectively;

Enogex s operations, including discontinued operations, reported net income of approximately $89.8 million, or $0.99 per diluted share of the Company s common stock, as compared to approximately $60.7 million, or $0.69 per diluted share, during 2005 and 2004, respectively; and

a net loss at the holding company of approximately $8.5 million, or $0.10 per diluted share, during 2005 as compared to a net loss of approximately $14.8 million, or $0.18 per diluted share, during 2004 reflecting lower net interest expense of approximately $9.6 million partially offset by a lower income tax benefit of approximately $3.8 million.

2004 compared to 2003. The Company reported net income of approximately $153.5 million, or $1.73 per diluted share, as compared to approximately $129.8 million, or $1.58 per diluted share, for the years ended December 31, 2004 and 2003, respectively. The increase in net income during 2004 as compared to 2003 was primarily due to:

- OG&E reported net income of approximately $107.6 million, or $1.22 per diluted share of the Company s common stock, as compared to approximately $115.4 million, or $1.41 per diluted share, during 2004 and 2003, respectively;
- Enogex s operations, including discontinued operations, reported net income of approximately $60.7 million, or $0.69 per diluted share of the Company s common stock, as compared to approximately $26.9 million, or $0.33 per diluted share, during 2004 and 2003, respectively; and
- a net loss at the holding company of approximately $14.8 million, or $0.18 per diluted share, during 2004 as compared to a net loss of approximately $12.5 million, or $0.16 per diluted share, during 2003 reflecting an increase in net interest expense due to a write-off of approximately $5.9 million of unamortized debt issuance costs for the trust preferred securities which were redeemed at par on October 15, 2004, partially offset by an increase in other income.

Regulatory Matters

Gas Transportation and Storage Agreement

As part of the settlement of an OG&E rate case in November 2002 (the Settlement Agreement), OG&E agreed to consider competitive bidding as a basis to select its provider for gas transportation service to its natural gas-fired generation facilities pursuant to the terms set forth in the Settlement Agreement. Because the required integrated service was not available in the marketplace from parties other than Enogex, OG&E advised the OCC that, after careful consideration, competitive bidding for gas transportation was rejected in favor of a new intrastate integrated, firm no-notice load following gas transportation and storage services agreement with Enogex. This seven-year agreement provides for gas transportation and storage services for each of OG&E s natural gas-fired generation facilities. OG&E will pay Enogex annual demand fees of approximately $46.8 million for the right to transport specified maximum daily quantities (MDQ) and maximum hourly quantities (MHQ) of gas at various minimum gas delivery pressures depending on the operational needs of the individual generating facility. In addition, OG&E supplies system fuel in-kind for its pro-rata share of actual fuel and lost and unaccounted for gas on the transportation system. To the extent OG&E transports gas in quantities in excess of the prescribed MDQ s or MHQ s, it pays an overrun service charge. During the years ended December 31, 2005, 2004 and

2003, OG&E paid Enogex approximately $47.6 million, $49.6 million and $44.7 million, respectively, for gas transportation and storage services.

On July 14, 2005, the OCC issued an order in this case approving a $41.9 million annual recovery. The OCC order disallowed the recovery by OG&E of the amount that Enogex charges OG&E for the cost of fuel used, or otherwise unaccounted for, in providing natural gas transportation and storage service to OG&E. Over the last three years, this amount has ranged from $1.2 million to $3.7 million annually. This amount was approximately $1.2 million in 2005 and is projected to be approximately $0.5 million in 2006. The OCC s order required OG&E to refund to its Oklahoma customers the difference between the amounts collected from such customers in the past based on an annual rate of $46.8 million for gas transportation and storage services and the $41.9 million annual rate authorized by the OCC s order. Based on the order, OG&E s refund obligation was approximately $8.8 million. OG&E began refunding this obligation in September 2005 through its automatic fuel adjustment clause. The balance of the refund obligation was approximately $6.0 million at December 31, 2005. For further information, see Note 15 of Notes to Consolidated Financial Statements.

In connection with the Enogex gas transportation and storage agreement, OG&E has also recorded a refund obligation in Arkansas. OG&E expects to meet with the APSC in early 2006 to determine the amount of the refund. ,OG&E estimated its refund obligation to be approximately $1.1 million at December 31, 2005 to Arkansas customers assuming the Arkansas refund obligation is calculated consistent with the Oklahoma calculation.

OG&E Oklahoma Rate Case Filing

On May 20, 2005, OG&E filed with the OCC an application for an annual rate increase of approximately $89.1 million to recover, among other things, its investment in, and the operating expenses of, the McClain Plant. The application also included, among other things, implementation of enhanced reliability programs in OG&E s system, increased fuel oil inventory, the establishment of a separate recovery mechanism for major storm expense, the establishment of new rate classes for public schools and related facilities, the establishment of a military base rider, the establishment of a new low income assistance tariff and the proposal to make the guaranteed flat bill pilot tariff permanent for residential and small business customers.

On September 12, 2005, several parties filed responsive testimony reflecting various positions on the issues related to this case. In particular, the testimony of the OCC Staff recommended that OG&E be entitled a rate increase of approximately $13.0 million, one-seventh the amount requested by OG&E in its May 20, 2005 application. The recommendations in the testimony of the Attorney General s office and the Oklahoma Industrial Energy Consumers recommended a rate decrease of approximately $24 million and $31 million, respectively. Hearings in the rate case began on October 10, 2005 and concluded on October 24, 2005. On November 3, 2005, the Referee appointed by the OCC for this proceeding issued a report recommending an estimated rate increase of approximately $42 million for OG&E. On December 12, 2005, the OCC issued an order providing for a $42.3 million increase in rates and a 10.75 percent return on equity, based on a capital structure consisting of 55.7 percent equity and 44.3 percent debt. The new rates became effective in January 2006. Also included in the order, among other things, are new depreciation rates effective January 2006 and a provision which modified OG&E s mechanism for the recovery of over or under recovered fuel costs from its customers to allow interest to be applied to the over or under recovery. For further information regarding this rate case, see Note 15 of Notes to Consolidated Financial Statements.

Coal Shipment Disruption

In July 2005, OG&E received notification from Union Pacific Railroad (Union Pacific) that, in May 2005, Union Pacific and BNSF Railway (BNSF) experienced successive derailments on the jointly-owned rail line serving the Southern Powder River Basin coal producers. According to Union Pacific, these two derailments were caused by track that had become unstable from an accumulation of coal dust in the roadbed combined with unusually heavy rainfall. BNSF, which maintains and operates the line, concluded that a significant part of the line needed to be repaired before normal train operations could resume. While the repairs were taking place, Union Pacific was unable to operate at full capacity from the Powder River Basin. In November 2005, Union Pacific notified OG&E that the South Powder River Basin joint line force majeure condition that was declared in May 2005 had ended. On December 2, 2005, BNSF completed the enhanced joint line maintenance program which opened the way for a return to normal operating conditions. It is expected that as rail traffic improves, OG&E will be able to increase its level of coal inventories. At December 31, 2005, OG&E had slightly more than 20 days of coal supply for each of its coal-fired units at its Sooner and Muskogee generating plants.

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Potential New Enogex Project

On November 4, 2005, Enogex announced that it had entered into a letter of intent with El Paso Corporation (El Paso) that is designed to accelerate El Paso s Continental Connector Project. The letter of intent contemplates arrangements by which El Paso or an affiliate would execute an initial lease of up to 750,000 decatherms per day (Dth/day) of capacity on the Enogex pipeline system, with an option to expand up to 1.5 million Dth/day, so that the leased Enogex pipeline capacity would become an integral part of the Continental Connector Project. The letter of intent also contemplates a commitment by Enogex to secure up to 500,000 Dth/day of capacity subscriptions for the project. These arrangements would significantly reduce the amount of new mainline construction required for the project, resulting in less environmental disturbance and an earlier in-service target date of winter 2007-2008.

Under the letter of intent, the Continental Connector Project will use existing or expanded El Paso pipeline systems to transport capacity-constrained natural gas from Rocky Mountain and mid-continent supply regions to Custer, Oklahoma. At Custer, this gas and local mid-continent production will be transported on existing and expanded Enogex systems for Continental Connector under a long-term lease arrangement for re-delivery in the vicinity of Bennington, Oklahoma. From there, gas will be transported on new El Paso pipeline facilities through the Perryville, Louisiana, Hub to a termination with Tennessee and Southern Natural Pipelines at Pugh, Mississippi.

Enogex intends to work with El Paso to determine whether to advance this project. However, the commitments and obligations under the letter of intent are subject to various conditions, including definitive documentation and boards of directors and regulatory approvals and there can be no assurance that the conditions will be satisfied. Pending satisfaction of these conditions, Enogex does not expect to incur material expenditures.

2006 Outlook

The Company s 2006 earnings guidance, excluding any gains on asset sales, and key assumptions are detailed below. The Company assumes approximately 91.2 million average diluted shares outstanding, cash flow from operations of between $320 and $330 million and an effective tax rate of 36.3 percent in its 2006 earnings guidance.

(In millions, except per share data)	Dollars	Diluted EPS
OG&E	$124 - $128	$1.36 - $1.40
Enogex	$44 - $48	$0.48 - $0.53
Holding Company	($7) - ($9)	($0.08) - ($0.10)
Total	$159 - $169	$1.75 - $1.85

Key assumptions for 2006 are:

OG&E

- Normal weather patterns are experienced;
- Gross margin on revenues (gross margin) on weather-adjusted, retail electric sales increases approximately two percent;
- Oklahoma rate increase of approximately $42.3 million;
- The General Motors Oklahoma City plant closes, as announced, in early 2006, which is expected to reduce OG&E s gross margin by approximately $2.2 million annually;
- Operating and maintenance expenses increase approximately $7 million primarily due to increased employee and benefit costs as well as costs associated with the acquisition of the McClain Plant;
- Interest costs increase approximately $14 million primarily due to the acquisition of the McClain Plant and higher interest rates associated with variable debt;
- Capital expenditures for investment in OG&E s generation, transmission and distribution system are approximately $237 million in 2006; and
- Funding for the Company s pension plan may be up to $90 million in 2006, of which up to $69.9 million may be allocated to OG&E.

OG&E has significant seasonality in its earnings. OG&E typically shows minimal earnings or slight losses 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

- Total Enogex gross margin of approximately $272 million to $279 million as compared to approximately $258 million in 2005:
  - Transportation and storage gross margin contribution of approximately $116 million as compared to approximately $99 million in 2005:
    - The increase in gross margin is primarily attributable to a reduction in fuel losses; and
    - Approximately 80 percent of Enogex s transportation and storage contracts are firm contracts with revenues primarily from gas transportation contracts with utilities in Oklahoma and Arkansas and independent power producers in Oklahoma.

Gathering and processing gross margin contribution of approximately $147 million to $154 million as compared to approximately $156 million in 2005:

Gross margin increase in Enogex s gathering and processing business in 2006 primarily due to continued efforts to increase margins from the negotiation of both new contracts and replacement contracts;

Volumes in Enogex s gathering and processing business remain flat from 2005;

Commodity spreads are $1.95 to $2.22 per Million British thermal unit (MMBtu) in 2006 as compared to $2.55 per MMBtu in 2005 and average natural gas liquids prices are $0.94 to $1.16 per gallon in 2006 as compared to $1.02 per gallon in 2005; and

Enogex s gathering and processing business has 277 new well connections in 2006.

Marketing gross margin contribution of approximately $9 million as compared to approximately $3 million in 2005;

Operating and maintenance expenses increase approximately $7 million primarily due to increased employee and benefit costs;

Interest expense remains relatively flat in 2006;

Capital expenditures for investment in Enogex s pipeline system are approximately $60 million in 2006; and

Funding for the Company s pension plan may be up to $90 million in 2006, of which up to $7.4 million may be allocated to Enogex.

Enogex expects to continue to evaluate the strategic fit and financial performance of each of its assets in an effort to ensure a proper economic allocation of resources. The magnitude and timing of any potential impairment or gain on the disposition of any assets have not been included in the 2006 earnings guidance.

Holding Company

Funding for the Company s pension plan may be up to $90 million in 2006, of which approximately $12.7 million may be allocated to the holding company; and

Interest expense decreases slightly in 2006 due to lower levels of short-term debt offset by higher short-term interest rates.

Dividend Policy

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 target payout ratio for the Company is to pay out as dividends approximately 75 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 our shareholder base, our financial position, our growth targets, the composition of our assets and investment opportunities. Management, after considering estimates of future earnings and numerous other factors, expects at this time that it will continue to recommend to the Board of Directors a continuance of the current dividend rate.

6

Results of Operations

The following discussion and analysis presents factors which affected the Company s consolidated results of operations for the years ended December 31, 2005, 2004 and 2003 and the Company s consolidated financial position at December 31, 2005 and 2004. 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)	**2005**	2004	2003
Operating income	**$ 330.5**	$ 303.8	$ 297.9
Net income	**$ 211.0**	$ 153.5	$ 129.8
Basic average common shares outstanding	**90.3**	88.0	81.8
Diluted average common shares outstanding	**90.8**	88.5	82.1
Basic earnings per average common share	**$ 2.34**	$ 1.74	$ 1.59
Diluted earnings per average common share	**$ 2.32**	$ 1.73	$ 1.58
Dividends declared per share	**$ 1.33**	$ 1.33	$ 1.33

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 unusual or infrequent items, the cost of capital and income taxes.

Operating Income (Loss) by Business Segment

(In millions)	**2005**	2004	2003
OG&E (Electric Utility)	**$ 232.2**	$ 192.3	$ 216.3
Enogex (Natural Gas Pipeline) (A)	**97.7**	112.6	82.1
Other Operations (B)	**0.6**	(1.1)	(0.5)
Consolidated operating income	**$ 330.5**	$ 303.8	$ 297.9

(A) Excludes discontinued operations. See Enogex Discontinued Operations for a further discussion.

(B) Other Operations primarily includes unallocated corporate expenses and consolidating eliminations.

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

7

OG&E

(Dollars in millions)	**2005**	2004	2003
Operating revenues	**$ 1,720.7**	$ 1,578.1	$ 1,517.1
Cost of goods sold	**994.2**	914.2	837.3
Gross margin on revenues	**726.5**	663.9	679.8
Other operation and maintenance	**309.2**	301.9	294.8
Depreciation	**134.4**	122.7	121.8
Taxes other than income	**50.7**	47.0	46.9
Operating income	**232.2**	192.3	216.3
Other income (loss)	**(2.3)**	5.8	0.6
Other expense	**3.0**	2.7	3.2
Interest income	**2.6**	2.7	0.7
Interest expense	**47.2**	37.5	38.8
Income tax expense	**52.6**	53.0	60.2
Net income	**$ 129.7**	$ 107.6	$ 115.4
Operating revenues by classification			
Residential	**$ 663.6**	$ 611.4	$ 601.4
Commercial	**418.9**	389.9	372.5
Industrial	**355.6**	326.7	293.4
Public authorities	**173.1**	158.5	146.1
Sales for resale	**67.7**	57.0	57.7
Provision for refund on gas transportation and storage case	**(2.0)**	(6.9)	---
System sales revenues	**1,676.9**	1,536.6	1,471.1
Off-system sales revenues	**4.9**	0.8	4.1
Other	**38.9**	40.7	41.9
Total operating revenues	**$ 1,720.7**	$ 1,578.1	$ 1,517.1
MWH (A) sales by classification (in millions)			
Residential	**8.5**	7.9	8.2
Commercial	**6.0**	5.7	5.8
Industrial	**7.2**	7.0	6.8
Public authorities	**2.8**	2.7	2.7
Sales for resale	**1.5**	1.4	1.5
System sales	**26.0**	24.7	25.0
Off-system sales	**0.1**	0.1	0.1
Total sales	**26.1**	24.8	25.1
Number of customers	**745,493**	735,008	725,470
Average cost of energy per KWH (B) - cents			
Fuel	**3.011**	2.887	2.454
Fuel and purchased power	**3.300**	3.436	3.128
Degree days (C)			
Heating			
Actual	**3,159**	3,114	3,488
Normal	**3,631**	3,650	3,631
Cooling			
Actual	**2,163**	1,839	1,898
Normal	**1,911**	1,911	1,911

(A) Megawatt-hour.

(B) Kilowatt-hour.

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

8

2005 compared to 2004. OG&E s operating income increased approximately $39.9 million or 20.7 percent in 2005 as compared to 2004. The increase in operating income was primarily attributable to higher gross margins partially offset by higher operating expenses.

Gross margin, which is operating revenues less cost of goods sold, was approximately $726.5 million in 2005 as compared to approximately $663.9 million in 2004, an increase of approximately $62.6 million or 9.4 percent. The gross margin increased primarily due to:

- warmer weather in OG&E s service territory, which increased the gross margin by approximately $33.4 million;
- price variance due to sales and customer mix and rate increases authorized in the OCC order in December 2005 that are included in the unbilled revenue calculation at December 31, 2005, which increased the gross margin by approximately $13.2 million;
- new customer growth primarily in the residential and commercial sectors of OG&E s service territory, which increased the gross margin by approximately $6.6 million; and
- increased demand by industrial customers in OG&E s service territory, which increased the gross margin by approximately $5.8 million.

Cost of goods sold for OG&E consists of fuel used in electric generation and purchased power. Fuel expense was approximately $795.4 million in 2005 as compared to approximately $645.1 million in 2004, an increase of approximately $150.3 million or 23.3 percent. The increase was primarily due to increased generation and a higher average cost of fuel per kwh. 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 2005 and 2004, OG&E s fuel mix was 70 percent coal and 30 percent natural gas. Though OG&E has a higher installed capability of generation from natural gas units of 58 percent, it has been more economical to generate electricity for our customers with lower priced coal. Purchased power costs were approximately $198.8 million in 2005 as compared to approximately $269.1 million in 2004, a decrease of approximately $70.3 million or 26.1 percent. The decrease was primarily due to OG&E s completion of the acquisition of the McClain Plant in 2004, the termination of a power purchase contract in August 2004 which was replaced with a new contract in September 2004 and the scheduled decrease in cogeneration capacity payments for another power purchase contract, which became effective in January 2005.

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 automatic fuel adjustment clauses. The automatic 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.

Other operating and maintenance expenses were approximately $309.2 million in 2005 as compared to approximately $301.9 million in 2004, an increase of approximately $7.3 million or 2.4 percent. The increase in other operating and maintenance expenses was primarily due to:

- higher salaries, wages, pension and other employee expenses of approximately $8.6 million; and
- higher materials and supplies expense of approximately $2.0 million.

These increases in other operating and maintenance expenses were partially offset by lower allocations from the holding company of approximately $6.9 million primarily due to lower miscellaneous corporate expenses. This variance includes other operating and maintenance expenses associated with the acquisition of the McClain Plant, which ceased being recorded as a regulatory asset on July 8, 2005.

Depreciation expense was approximately $134.4 million in 2005 as compared to approximately $122.7 million in 2004, an increase of approximately $11.7 million or 9.5 percent, primarily due to a higher level of depreciable plant in addition to depreciation expense associated with the acquisition of the McClain Plant, which ceased being recorded as a regulatory asset on July 8, 2005.

Taxes other than income was approximately $50.7 million in 2005 as compared to approximately $47.0 million in 2004, an increase of approximately $3.7 million or 7.9 percent, primarily due to increased ad valorem taxes. This variance includes ad valorem taxes associated with the acquisition of the McClain Plant, which ceased being recorded as a regulatory asset on July 8, 2005.

Other income includes, among other things, contract work performed by OG&E, non-operating rental income, gain on the sale of assets and miscellaneous non-operating income. Other income was a loss of approximately $2.3 million in 2005 as compared to income of approximately $5.8 million in 2004, a decrease of approximately $8.1 million. The decrease in other income was primarily due to gains recognized in 2004 of approximately $3.5 million from the sale of OG&E s interests in its natural gas producing properties and the sale of land near the Company s principal executive offices which gains were reversed in 2005 and reclassified to Other Deferred Credits and Other Liabilities in the Consolidated Balance Sheet as a regulatory liability. Also contributing to the decrease in other income was a gain in 2004 of approximately $0.6 million from the repurchase of outstanding heat pump loans in addition to approximately $0.9 million due to the allowance for other funds used during construction in 2004.

Other expense includes, among other things, expenses from the losses on the sale of assets, miscellaneous charitable donations, expenditures for certain civic, political and related activities and miscellaneous deductions. Other expense was approximately $3.0 million in 2005 as compared to approximately $2.7 million in 2004, an increase of approximately $0.3 million or 11.1 percent which was primarily due to an increase of approximately $0.2 million in charitable contributions.

Net interest expense includes interest income, interest expense and other interest charges. Net interest expense was approximately $44.6 million in 2005 as compared to approximately $34.8 million in 2004, an increase of approximately $9.8 million or 28.2 percent. The increase in net interest expense was primarily due to:

- an increase in interest expense of approximately $4.3 million due to interest on debt associated with the McClain Plant acquisition, which OG&E ceased recording as a regulatory asset on July 8, 2005;
- an increase in interest expense of approximately $4.2 million due to an increase in variable interest rates associated with the Company s interest rate swap agreement and variable rate industrial authority bonds; and
- an increase in interest expense of approximately $3.3 million for additional interest expense related to income taxes as a result of new guidelines issued by the Internal Revenue Service related to a change in the method of accounting used to capitalize costs for self-construction for income tax purposes only.

These increases in net interest expense were partially offset by:

- a decrease in interest expense of approximately $1.2 million due to lower interest rates on short-term debt used to temporarily fund the repayment of higher cost matured and called long-term debt; and
- a reduction in interest expense of approximately $0.5 million due to an increase in the allowance for borrowed funds used during construction.

Income tax expense was approximately $52.6 million in 2005 as compared to approximately $53.0 million in 2004, a decrease of approximately $0.4 million or 0.8 percent. The decrease in income tax expense was primarily due to:

- a reduction in tax accruals in 2005 related to Medicare Part D of approximately $2.6 million;
- a reduction in excess deferred taxes in 2005 of approximately $2.1 million; and
- an increase in Oklahoma state income tax credits of approximately $0.6 million in 2005 as compared to 2004.

These decreases in income tax expense were partially offset by higher pre-tax income for OG&E.

2004 compared to 2003. OG&E s operating income decreased approximately $24.0 million or 11.1 percent in 2004 as compared to 2003. The decrease in operating income was primarily attributable to lower gross margins and higher operating expenses.

Gross margin was approximately $663.9 million in 2004 as compared to approximately $679.8 million in 2003, a decrease of approximately $15.9 million or 2.3 percent. The gross margin decreased primarily due to:

- cooler weather in OG&E s service territory which reduced the gross margin by approximately $15.7 million;
- lower margins related to sales to wholesale customers primarily resulting from reduced sales of power under a new wholesale contract with an existing customer which reduced the gross margin by approximately $3.2 million; and
- the timing of fuel recoveries which decreased the gross margin by approximately $1.7 million.

These decreases in gross margin were partially offset by growth in OG&E s service territory which increased the gross margin by approximately $4.9 million.

Fuel expense was approximately $645.1 million in 2004 as compared to approximately $544.4 million in 2003, an increase of approximately $100.7 million or 18.5 percent. The increase was primarily due to an increase in the average cost of fuel per kwh, primarily due to higher natural gas prices despite lower mwh sales. 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 2004, OG&E s fuel mix was 70 percent coal and 30 percent natural gas as compared to 77 percent coal and 23 percent natural gas in 2003. Though OG&E has a higher installed capability of generation from natural gas units of 59 percent, it has been more economical to generate electricity for our customers with lower priced coal. Purchased power costs were approximately $269.1 million in 2004 as compared to approximately $292.9 million in 2003, a decrease of approximately $23.8 million or 8.1 percent. The decrease was primarily due to OG&E s acquisition of the McClain Plant in July 2004 and the termination of power purchase contracts in December 2003 and August 2004.

Other operating and maintenance expenses were approximately $301.9 million in 2004 as compared to approximately $294.8 million in 2003, an increase of approximately $7.1 million or 2.4 percent. The increase in other operating and maintenance expenses was primarily due to:

- increased outside services expense of approximately $18.1 million;
- increased materials and supplies expense of approximately $2.0 million;
- increased employee expenses of approximately $2.0 million; and
- increased liability insurance expense of approximately $0.9 million due to increased insurance premiums.

These increases in other operating and maintenance expenses were partially offset by lower salaries and wages expense of approximately $5.9 million and lower pension and benefit expense of approximately $6.4 million primarily due to more projects on which the costs are capitalized and are not being expensed currently.

Depreciation expense was approximately $122.7 million in 2004 as compared to approximately $121.8 million in 2003, an increase of approximately $0.9 million or 0.7 percent, primarily due to a higher level of depreciable plant. Also, another factor affecting 2004 results was an overall increase of approximately $3.8 million in the reserves related to litigation.

Other income was approximately $5.8 million in 2004 as compared to approximately $0.6 million in 2003, an increase of approximately $5.2 million. The increase in other income was primarily due to gains in 2004 of approximately $3.2 million from the sale of OG&E s interests in its natural gas producing properties, approximately $0.6 million from the repurchase of outstanding heat pump loans and approximately $0.3 million from the sale of land and buildings near the Company s principal executive offices. Also contributing to the increase in other income was an increase of approximately $0.9 million due to the allowance for equity funds used during construction.

Other expense was approximately $2.7 million in 2004 as compared to approximately $3.2 million in 2003, a decrease of approximately $0.5 million or 15.6 percent. The decrease in other expense was primarily due to realized losses of approximately $0.4 million from the sale of miscellaneous assets in 2003.

Net interest expense was approximately $34.8 million in 2004 as compared to approximately $38.1 million in 2003, a decrease of approximately $3.3 million or 8.7 percent. The decrease in net interest expense was primarily due to:

- an increase in interest income of approximately $1.7 million due to the interest portion of an income tax refund related to prior periods;
- a reduction in interest expense of approximately $0.7 million due to OG&E having lower average borrowing outstanding from the parent in 2004 as compared to 2003; and
- a reduction in interest expense of approximately $1.1 million due to an increase in the allowance for borrowed funds used during construction.

Income tax expense was approximately $53.0 million in 2004 as compared to approximately $60.2 million in 2003, a decrease of approximately $7.2 million or 12.0 percent. The decrease in income tax expense was primarily due to:

- lower pre-tax income for OG&E; and
- the recognition of additional Oklahoma state tax credits of approximately $2.0 million during 2004.

Enogex Continuing Operations

(Dollars in millions)	**2005**	2004	2003
Operating revenues	**$ 4,369.1**	$ 3,421.7	$ 2,306.2
Cost of goods sold	**4,111.2**	3,143.6	2,070.2
Gross margin on revenues	**257.9**	278.1	236.0
Other operation and maintenance	**100.5**	97.3	87.4
Depreciation	**43.9**	44.0	40.9
Impairment of assets	**---**	7.8	9.2
Taxes other than income	**15.8**	16.4	16.4
Operating income	**97.7**	112.6	82.1
Other income	**0.8**	4.5	0.7
Other expense	**0.3**	0.3	1.6
Interest income	**2.9**	3.2	0.8
Interest expense	**32.6**	32.2	34.1

Income tax expense	**23.6**	33.1	19.8
Income from continuing operations	**$ 44.9**	$ 54.7	$ 28.1
New well connects	**272**	258	214
Gathered volumes TBtud (A)	**1.01**	0.98	0.95
Incremental transportation volumes TBtud	**0.45**	0.39	0.36
Total throughput volumes TBtud	**1.46**	1.37	1.31
Natural gas processed Mmcfd (B)	**518**	502	414
Natural gas liquids sold (keep-whole) million gallons	**296**	263	207
Natural gas liquids sold (POL and fixed-fee) million gallons	**15**	16	18
Total natural gas liquids sold million gallons	**311**	279	225
Average sales price per gallon	**$ 0.847**	$ 0.720	$ 0.595

(A) Trillion British thermal units per day.

(B) Million cubic feet per day.

2005 compared to 2004. Enogex s operating income decreased approximately $14.9 million or 13.2 percent as compared to 2004. The decrease in operating income was primarily attributable to decreased gross margins of approximately $21.1 million in Enogex s marketing business and approximately $15.4 million in Enogex s transportation and storage business, which were partially offset by increased gross margins of approximately $16.3 million in Enogex s gathering and processing business. These decreases in operating income also were partially offset by an asset impairment charge of approximately $7.8 million recorded in 2004 with no similar item recorded in 2005.

Transportation and storage contributed approximately $99.1 million of Enogex s gross margin in 2005 as compared to approximately $114.5 million in 2004, a decrease of approximately $15.4 million or 13.4 percent. The gross margin decreased primarily due to:

- storage field gas losses, increased costs associated with natural gas purchases and sales, increased costs from electric compression, reduced fuel recoveries due to timing and system fuel volumes previously recorded in Enogex s transportation and storage business which are now being recorded in Enogex s gathering and processing business, which collectively reduced the gross margin by approximately $20.5 million; and
- reduced demand fees due to fewer overrun service charges with OG&E and the loss of firm contracts, which reduced the gross margin by approximately $2.1 million.

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

- increased crosshaul prices and volumes, which increased the gross margin by approximately $5.3 million; and
- increased commodity and interruptible revenues, which increased the gross margin by approximately $1.5 million.

Gathering and processing contributed approximately $156.1 million of Enogex s gross margin in 2005 as compared to approximately $139.8 million in 2004, an increase of approximately $16.3 million or 11.7 percent. Gathering gross margins increased approximately $14.6 million or 17.2 percent in 2005 as compared to 2004. The gathering gross margin increased primarily due to:

- contractual fuel gains primarily due to higher natural gas prices and renegotiated contracts, which increased the gross margin by approximately $8.0 million;
- increased fuel over recoveries due to higher natural gas prices, 2005 fuel reserve and system fuel volumes previously recorded in Enogex s transportation and storage business which is now being recorded in Enogex s gathering and processing business, which increased the gross margin by approximately $4.2 million;
- higher volumes on the low pressure gathering systems, which increased the gross margin by approximately $2.2 million;
- higher volumes related to compression and dehydration, which increased the gross margin by approximately $2.2 million; and
- higher margin on natural gas sales reflective of opportunities in the marketplace, which increased the gross margin by approximately $2.1 million.

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

- higher cost of electricity in 2005, which reduced the gross margin by approximately $3.0 million; and
- lower volumes on the high pressure gathering systems, which reduced the gross margin by approximately $0.8 million.

Processing gross margins increased approximately $1.7 million or 3.1 percent in 2005 as compared to 2004 primarily due to:

- increased condensate margins primarily due to higher condensate prices, which increased the gross margin by approximately $3.0 million; and
- increased percent of liquids margins primarily due to higher natural gas prices, which increased the gross margin by approximately $1.4 million.

These increases in the processing gross margin were partially offset by decreased net keep-whole margins primarily due to higher natural gas prices, which reduced the gross margin by approximately $3.1 million.

Marketing contributed approximately $2.7 million of Enogex s gross margin in 2005 as compared to approximately $23.8 million in 2004, a decrease of approximately $21.1 million or 88.6 percent. The gross margin decreased primarily due to:

- less favorable market conditions and trading activity, which reduced the gross margin by approximately $13.0 million;
- a correction to the accounting procedure for park and loan transactions (natural gas storage transactions) in 2004, which reduced the gross margin by approximately $7.7 million (see Note 13 of Notes to Consolidated Financial Statements); and
- losses incurred related to Enogex s position on the Cheyenne Plains transportation agreement, which reduced the gross margin by approximately $3.6 million.

These decreases in the marketing gross margin were partially offset by:

- lower demand fees paid for storage services due to establishing new rates for the new storage season, which began April 1, 2004 which increased the gross margin by approximately $2.5 million; and gains in storage activity, which increased the gross margin by approximately $0.7 million.

Enogex s other operating and maintenance expenses were approximately $100.5 million in 2005 as compared to approximately $97.3 million in 2004, an increase of approximately $3.2 million or 3.3 percent. The increase in other operating and maintenance expenses was primarily due to:

higher outside service costs related to business development projects in 2005, system software implementation in 2005 and work performed to maintain the integrity and safety of Enogex s pipeline of approximately $3.9 million; and

expenses related to a pipeline rupture in the second quarter 2005 of approximately $0.5 million.

These increases in other operating and maintenance expenses were partially offset by an uncollectible debt reserve of approximately $1.1 million recorded in 2004 with no similar reserve recorded in 2005.

Impairment of assets was approximately $7.8 million ($4.8 million after tax) in 2004 as a result of recording an impairment charge during the third quarter of 2004. The impairment charge related to certain Enogex natural gas pipeline assets that served a particular customer s power plants pursuant to a transportation agreement that was terminated by the customer effective December 31, 2004. There were no impairments recorded in 2005.

Other income was approximately $0.8 million in 2005 as compared to approximately $4.5 million in 2004, a decrease of approximately $3.7 million or 82.2 percent. The decrease in other income was primarily due to a gain in 2004 of approximately $3.0 million from the sale of certain of Enogex s compression and processing assets in 2004 in addition to approximately $0.8 million received related to a bankruptcy settlement from one of Enogex s customers during the third quarter of 2004.

Net interest expense was approximately $29.7 million in 2005 as compared to approximately $29.0 million in 2004, an increase of approximately $0.7 million or 2.4 percent. The increase in net interest expense was primarily due to a decrease in interest income of approximately $0.8 million. The decrease in interest income reflects a decrease of $1.9 million due to the interest portion of an income tax refund related to prior periods which was received in 2004 with no similar activity recorded in 2005 partially offset by an increase of approximately $1.1 million in interest income from parent due to funds received from the sale of EAPC in October 2005.

Income tax expense was approximately $23.6 million in 2005 as compared to approximately $33.1 million in 2004, a decrease of approximately $9.5 million or 28.7 percent. The decrease in income tax expense was primarily due to:

- lower pre-tax income for Enogex; and
- a reduction in excess deferred taxes of approximately $3.2 million in 2005.

These decreases in income tax expense were partially offset by a decrease in Oklahoma state income tax credits of approximately $1.6 million in 2005 as compared to 2004.

For 2005, Enogex s net income, including the discontinued operations discussed below under the caption Enogex Discontinued Operations, was approximately $89.9 million as compared to approximately $60.7 million in 2004. During 2005, Enogex had an increase in net income of approximately $40.2 million relating to various items that the Company does not consider to be reflective of the ongoing profitability of Enogex s business. These increases in net income include:

- a gain on the sale of EAPC in October 2005 of approximately $36.7 million;
- income from discontinued operations of approximately $6.4 million; and
- a gain on the sale of Enerven in August 2005 of approximately $1.8 million.

These increases to net income were partially offset by a correction to the accounting procedure for park and loan transactions in 2004 of approximately $4.7 million.

During the year ended December 31, 2004, Enogex had an increase in net income of approximately $9.9 million relating to various items that the Company does not consider to be reflective of the ongoing profitability of Enogex s business. These increases in net income include:

- income from discontinued operations of approximately $6.0 million;
- authorized recovery of previously under recovered fuel of approximately $3.8 million;
- a gain on the sale of Enogex compression and processing assets of approximately $1.8 million;
- an imbalance settlement with a customer of approximately $1.6 million;
- a net Oklahoma investment tax credit of approximately $1.0 million; and
- a settlement related to a customer bankruptcy of approximately $0.5 million.

These increases to net income were partially offset by:

- a net impairment charge of approximately $4.8 million.

14

2004 compared to 2003. Enogex s operating income from continuing operations in 2004 increased approximately $30.5 million or 37.1 percent as compared to 2003. Gross margins increased approximately $48.5 million in Enogex s gathering and processing business, which was partially offset by decreased gross margins of approximately $6.3 million in Enogex s transportation and storage business and approximately $0.1 million in Enogex s marketing business. The increase in operating income was also partially offset by higher operating expenses.

Transportation and storage contributed approximately $114.5 million of Enogex s gross margin in 2004 as compared to approximately $120.8 million in 2003, a decrease of approximately $6.3 million or 5.2 percent. The gross margin decreased primarily due to:

- certain contractual revenues recorded in transportation and storage in 2003 being recorded in gathering and processing in 2004 , which reduced the gross margin by approximately $12.7 million;
- the Calpine Energy Services, L.P. (Calpine Energy) settlement in 2003, which resulted in a one-time increase of approximately $2.0 million to the gross margin in 2003; and
- reduced fuel recoveries due to timing related to fuel recoveries, which reduced the gross margin by approximately $1.1 million.

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

- higher interruptible revenues and higher crosshaul revenues due to an increase in interruptible contract volumes and increased crosshaul margins and volumes, which increased the gross margin by approximately $5.0 million; and
- higher transportation and storage revenues in 2004 primarily due to the additional demand fees and overrun charges from the transportation and storage contract with OG&E, which was effective May 2003, which increased the gross margin by approximately $4.9 million.

Gathering and processing contributed approximately $139.8 million of Enogex s gross margin in 2004 as compared to approximately $91.3 million in 2003, an increase of approximately $48.5 million or 53.1 percent. Gathering gross margins increased approximately $27.6 million in 2004 as compared to 2003 primarily due to:

- the change in 2004 discussed above of recording certain contractual revenues in gathering and processing rather than in transportation and storage, which increased the gross margin by approximately $12.7 million;
- revenue improvements generated from an overall favorable business environment coupled with higher commodity prices and the negotiation of both new contracts and replacement contracts at better terms; and
- an increase in the number of well connects and the volumes of natural gas gathered.

Processing gross margins increased approximately $20.9 million in 2004 as compared to 2003 primarily due to:

- increased keep-whole, percent of liquids and condensate margins due to favorable commodity prices and higher keep-whole volumes, which increased the gross margin by approximately $21.9 million; and
- an expense reallocation of compressor fuel (from processing in 2003 to transportation and storage in 2004), which increased the gross margin by approximately $1.3 million.

Marketing contributed approximately $23.8 million of Enogex s gross margin in 2004 as compared to approximately $23.9 million in 2003, a decrease of approximately $0.1 million or 0.4 percent. The gross margin decreased primarily due to:

- lower gains from the sale of natural gas in storage in 2004 of approximately $12.1 million primarily due to Enogex recording approximately a $9.0 million pre-tax loss as a cumulative effect of a change in accounting principle in the first quarter of 2003 rather than recording this loss as a reduction of the gross margin. The cumulative effect of a change in accounting principle was the result of accounting for certain energy contracts and natural gas in storage at the lower of cost or market rather than on a mark-to-market basis;
- mark-to-market timing losses on natural gas storage inventory due to different pricing environments during 2004 as compared to 2003, which reduced the gross margin by approximately $2.2 million; and
- exiting the power marketing business in 2004 which reduced the gross margin by approximately $1.1 million.

These decreases in the marketing gross margin were partially offset by:

- new business activity in the marketing portfolio, which increased the gross margin by approximately $12.2 million; and
- lower demand fees expense for storage services due to establishing new rates for the new storage season which began April 1, which increased the gross margin by approximately $3.4 million.

Enogex s other operating and maintenance expenses were approximately $97.3 million in 2004 as compared to approximately $87.4 million in 2003, an increase of approximately $9.9 million or 11.3 percent. The increase in other operating and maintenance expenses was primarily due to:

- higher payroll, benefit and pension expenses of approximately $4.1 million due to hiring new employees, payment of overtime and salary increases;
- higher outside service costs of approximately $2.4 million related to work performed to maintain the integrity and safety of Enogex s pipeline;
- higher materials and supplies expense of approximately $2.3 million for repairs and maintenance of systems;
- higher uncollectibles expense of approximately $1.4 million due to miscellaneous accounts receivable items becoming over 180 days old; and
- higher legal expenses of approximately $0.6 million related to the Section 311 rate case and other litigation.

Depreciation expense was approximately $44.0 million in 2004 as compared to approximately $40.9 million in 2003, an increase of approximately $3.1 million or 7.6 percent. The increase was primarily due to a higher level of depreciable plant as the implementation of an information system was completed during the second quarter of 2004 in addition to accelerated depreciation recorded during the fourth quarter of 2004 related to the impairment involving four of Enogex s non-contiguous pipeline asset segments.

Impairment of assets was approximately $7.8 million in 2004 as compared to approximately $9.2 million in 2003, a decrease of approximately $1.4 million or 15.2 percent. During September 2004, Enogex received notification from a customer that a transportation agreement involving four of Enogex s non-contiguous pipeline asset segments located in West Texas and used to serve the customer s power plants would be terminated effective December 31, 2004. In connection with the preparation of the third quarter 2004 financial statements, Enogex performed an evaluation on these assets and concluded that an impairment charge needed to be recorded. The primary reason for this determination was that these four pipeline asset segments were originally built for the specific purpose of providing gas transmission service to this customers four power plants that have been or are in the process of being shut down, and, as a result, other alternative commercial uses for these facilities are considered unlikely. Also, in 2004, the Company reclassified several compressors and processing plants that were previously classified as assets held for sale to assets held and used. This decision was based on the fact these assets are no longer being marketed and the Company believes the value of the future benefit of holding these assets exceeds the current fair market value. As a result, in accordance with Financial Accounting Standards Board (FASB) Statement of Financial Accounting Standards (SFAS) No. 144, Accounting for the Impairment or Disposal of Long Lived Assets, the Company determined the fair value of these assets based on a third party valuation of the assets and, as a result, the Company recorded a net gain of approximately $0.8 million during 2004 related to reclassifying these assets from assets held for sale to assets held and used, which was recorded as a credit to Impairment of Assets on the Consolidated Statements of Income. During 2003, an evaluation of the horsepower of compression needed to meet the operational requirements of the Company s gathering and transmission system was performed based on the then current market conditions. The review identified compressor equipment that could be removed from the system and a pre-tax impairment loss of approximately $9.2 million was recorded in the fourth quarter of 2003 to recognize the difference between the carrying value of these units and their fair value expected to be realized in a disposal. The impairment recorded in the fourth quarter of 2003 resulted from plans to dispose of these assets at prices below the carrying amount. The fair value of these assets was determined based on third-party evaluations, prices for similar assets, historical data and projected cash flows.

Other income was approximately $4.5 million in 2004 as compared to approximately $0.7 million in 2003, an increase of approximately $3.8 million. The increase in other income was primarily due to:

a realized gain of approximately $3.0 million on the sale of certain of Enogex s compression and processing assets in 2004; and

a bankruptcy settlement from one of Enogex s customers of approximately $0.8 million during the third quarter of 2004.

16

Other expense was approximately $0.3 million in 2004 as compared to approximately $1.6 million in 2003, a decrease of approximately $1.3 million or 81.3 percent. The decrease in other expense was primarily due to:

realized losses of approximately $0.8 million from the sale of miscellaneous assets in 2003; and

a loss from the dissolution of a lease in the third quarter of 2003 of approximately $0.7 million.

Net interest expense was approximately $29.0 million in 2004 as compared to approximately $33.3 million in 2003, a decrease of approximately $4.3 million or 12.9 percent. The decrease in net interest expense was primarily due to:

an increase in interest income of approximately $1.9 million due to the interest portion of an income tax refund related to prior periods;

a reduction in interest expense due to a reduction of long-term debt of approximately $1.3 million; and

a reduction in commercial paper service fees of approximately $0.6 million due to the Company having a lower average commercial paper balance outstanding in 2004 as compared to 2003.

Income tax expense was approximately $33.1 million in 2004 as compared to approximately $19.8 million in 2003, an increase of approximately $13.3 million or 67.2 percent. The increase in income tax expense was primarily due to higher pre-tax income for Enogex. This increase in income tax expense was partially offset by the recognition of additional Oklahoma state tax credits of approximately $1.8 million during 2004.

For 2004, Enogex s net income, including the discontinued operations discussed below under the caption Enogex Discontinued Operations, was approximately $60.7 million as compared to approximately $26.9 million in 2003. During the year ended December 31, 2004, Enogex had an increase in net income of approximately $9.9 million relating to various items that the Company does not consider to be reflective of the ongoing profitability of Enogex s business. These increases in net income include:

income from discontinued operations of approximately $6.0 million;

authorized recovery of previously under recovered fuel of approximately $3.8 million;

a gain on the sale of Enogex compression and processing assets of approximately $1.8 million;

an imbalance settlement with a customer of approximately $1.6 million;

a net Oklahoma investment tax credit of approximately $1.0 million; and

a settlement related to a customer bankruptcy of approximately $0.5 million.

These increases to net income were partially offset by:

a net impairment charge of approximately $4.8 million.

During the year ended December 31, 2003, Enogex had an increase in net income of approximately $8.7 million relating to various items that the Company does not consider to be reflective of the ongoing profitability of Enogex s business. These increases in net income include:

authorized recovery of previously under recovered fuel of approximately $6.5 million;

income from discontinued operations of approximately $4.7 million;

a gain on the sale of assets of approximately $2.6 million;

a settlement related to a dispute with Calpine Energy of approximately $1.2 million; and

a pricing adjustment on a processing contract with a customer of approximately $1.1 million.

These increases to net income were partially offset by:

an impairment charge of approximately $5.7 million; and an income tax adjustment of approximately $1.7 million.

Enogex Discontinued Operations

In April 2005, Enogex Compression received an unsolicited offer to buy its interest in Enerven, a joint venture focused on the rental of natural gas compression assets. After evaluating this offer, Enogex Compression sold its interest in Enerven for approximately $7.3 million in August 2005. Enogex Compression recognized an after tax gain of approximately $1.8 million related to the sale of this business.

17

Enogex regularly evaluates the long term stability, profitability and core competency of each of its businesses within the regulatory and market framework in which each business operates. Based on these evaluations, in September 2005, Enogex announced that it had entered into an agreement to sell its interest in EAPC, which held the NOARK interest. This sale was completed on October 31, 2005. The Company received approximately $177.4 million cash proceeds and recognized an after tax gain of approximately $36.7 million from the sale of this business in the fourth quarter. Enogex used approximately $31.9 million of the proceeds to repay principal and accrued interest on long-term debt and approximately $46.7 million to pay taxes associated with EAPC. The balance of the proceeds of approximately $98.8 million will be used to invest, over time, in strategic assets to diversify its asset base.

As a result of these sale transactions, Enogex Compression s interest in Enerven and Enogex s interest in EAPC, both of which were part of the Natural Gas Pipeline segment, have been reported as discontinued operations for the years ended December 31, 2005, 2004 and 2003 in the Consolidated Financial Statements. Results for these discontinued operations are summarized and discussed below.

(In millions)	**2005**	2004	2003
Operating revenues	**$ 69.3**	$ 78.3	$ 79.8
Cost of goods sold	**48.6**	54.5	61.2
Gross margin on revenues	**20.7**	23.8	18.6
Other operation and maintenance	**3.6**	4.2	4.9
Depreciation	**2.3**	3.5	3.5
Taxes other than income	**0.9**	1.1	1.2
Operating income	**13.9**	15.0	9.0
Other income	**66.2**	---	7.8
Other expense	**0.1**	0.6	1.4
Net interest expense	**3.8**	5.0	5.6
Income tax expense	**31.3**	3.4	5.1
Net income	**$ 44.9**	$ 6.0	$ 4.7

2005 compared to 2004. Gross margin decreased approximately $3.1 million or 13.0 percent in 2005 as compared to 2004. The decrease was primarily due to the sale of EAPC in the fourth quarter of 2005 in addition to an overpayment of natural gas purchases in a prior period that was recognized in 2004 with no similar item recorded in 2005, which reduced the gross margin by approximately $0.8 million.

Depreciation expense decreased approximately $1.2 million or 34.3 percent in 2005 as compared to 2004 primarily due to ceasing depreciation expense in September 2005 when EAPC was reported as a discontinued operation.

Other income increased approximately $66.2 million or 100.0 percent in 2005 as compared to 2004 primarily due to a pre-tax gain of approximately $63.3 million recognized in the fourth quarter of 2005 related to the sale of EAPC and a pre-tax gain of approximately $2.9 million recognized in the third quarter of 2005 related to the sale of Enerven.

Net interest expense decreased approximately $1.2 million or 24 percent in 2005 as compared 2004. The decrease was primarily due to the sale of EAPC in October 2005 and the use of a portion of the sale proceeds to repay long-term debt.

Income tax expense increased approximately $27.9 million in 2005 as compared to 2004. The increase was primarily due to taxes paid related to the sale of EAPC and Enerven.

2004 compared to 2003. Gross margin increased approximately $5.2 million or 28.0 percent in 2004 as compared to 2003. The increase was primarily due to:

- increased margins on the purchase and sale of natural gas, which increased the gross margin by approximately $4.3 million; and
- natural gas purchases in a prior period that was recognized in 2004 with no similar item recorded in 2003, which increased the gross margin by approximately $0.8 million.

Other operating expenses decreased approximately $0.8 million or 8.3 percent in 2004 as compared to 2003. The increase was primarily due to approximately $1.1 million of operating expenses recorded in 2003 related to the NuStar Joint Venture (NuStar), with no corresponding items recorded in 2004, due to the sale of NuStar in February 2003.

Other income decreased approximately $7.8 million or 100.0 percent in 2004 as compared to 2003 primarily due to a gain of approximately $5.3 million related to the sale of approximately 29 miles of transmission lines of the OGT pipeline in the first quarter of 2003.

Other expense decreased approximately $0.8 million or 57.1 percent in 2004 as compared to 2003 primarily due to minority interest expense of approximately $1.1 million in the first quarter of 2003 related to the gain from the sale of approximately 29 miles of transmission lines of the

OGT pipeline that was attributable to the minority interest.

Financial Condition

The balance of Accounts Receivable was approximately $591.4 million and $484.5 million at December 31, 2005 and 2004, respectively, an increase of approximately $106.9 million or 22.1 percent. The increase was primarily due to an increase in OG&E s billings to its customers reflecting increased pass through of fuel costs resulting from significantly higher natural gas costs in December 2005 as compared to December 2004, colder weather and an increase in natural gas sales activity by Enogex in the fourth quarter of 2005.

The balance of Fuel Inventories was approximately $63.6 million and $89.0 million at December 31, 2005 and 2004, respectively, a decrease of approximately $25.4 million or 28.5 percent. The decrease is primarily due to a decrease in coal inventories resulting from decreased coal deliveries from the Powder River Basin due to ongoing railroad repairs as described in Overview Coal Shipment Disruption and a decrease in natural gas storage capacity in OGE Energy Resources, Inc. s (OERI) business activities.

The balance of current Price Risk Management assets was approximately $116.5 million and $54.3 million at December 31, 2005 and 2004, respectively, an increase of approximately $62.2 million. The increase was primarily due to higher natural gas prices associated with OERI s short-term physical natural gas purchase transactions and associated financial contracts. The volume of OERI s short-term physical natural gas activity and associated financial contracts outstanding at December 31, 2005 remained substantially unchanged from December 31, 2004.

The balance of Gas Imbalance asset was approximately $32.0 million and $99.8 million at December 31, 2005 and 2004, respectively, a decrease of approximately $67.8 million or 67.9 percent. The Gas Imbalance asset is comprised of planned or managed imbalances related to OERI s business, referred to as park and loan transactions, and pipeline and natural gas liquids imbalances, which are operational imbalances. Park and loan transactions were approximately $15.7 million and $76.0 million at December 31, 2005 and 2004, respectively, a decrease of approximately $60.3 million or 79.3 percent. The decrease was due to a decrease in park and loan transactions during 2005 in OERI s business activities.

The balance of Fuel Clause Under Recoveries was approximately $101.1 million and $54.3 million at December 31, 2005 and 2004, respectively, an increase of approximately $46.8 million or 86.2 percent. The increase in fuel clause under recoveries was due to OG&E s cost of fuel exceeding the amount billed to OG&E s customers in 2005. 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 cost in periods of rising prices above the baseline charge for fuel and over recovers fuel cost when prices decline below the baseline charge for fuel. Provisions in the fuel clauses are intended to allow OG&E to amortize under or over recovery. In September 2005, OG&E increased its Oklahoma fuel adjustment factor from 0.0112500 per kwh to 0.0171760 per kwh in order to reduce the under recovery.

The balance of Recoverable Take or Pay Gas Charges was approximately $4.9 million and $17.0 million at December 31, 2005 and 2004, respectively, a decrease of approximately $12.1 million or 71.2 percent. The balance of Provision for Payments of Take or Pay Gas was approximately $8.9 million and $21.0 million at December 31, 2005 and 2004, respectively, a decrease of approximately $12.1 million or 57.6 percent. The decrease was primarily due to the settlement of one of the two lawsuits reserved in the provision account.

The balance of long-term Price Risk Management assets was approximately $9.0 million and $16.4 million at December 31, 2005 and 2004, respectively, a decrease of approximately $7.4 million or 45.1 percent. The decrease was primarily due to lower levels of activity associated with OERI s long-term physical natural gas transactions and associated financial contracts outstanding at December 31, 2005 partially offset by higher natural gas prices.

The balance of McClain Plant deferred expenses was approximately $24.9 million and $11.0 million at December 31, 2005 and 2004, respectively, an increase of approximately $13.9 million. The increase was due to certain expenses including non-fuel operation and maintenance expenses, depreciation, cost of debt associated with the investment and ad valorem taxes being accrued as a regulatory asset for the 12-month period subsequent to the completion of the

19

McClain Plant acquisition. Such costs will be recovered over a four-year time period as authorized in the OCC order beginning in January 2006.

The balance of Short-Term Debt was approximately $30.0 million and $125.0 million at December 31, 2005 and 2004, respectively, a decrease of approximately $95.0 million or 76.0 percent. The decrease is primarily due to proceeds received from the sale of EAPC in October 2005 which were used to pay down the commercial paper balance partially offset by increasing daily operational needs of the Company.

The balance of Accounts Payable was approximately $510.4 million and $470.3 million at December 31, 2005 and 2004, respectively, an increase of approximately $40.1 million or 8.5 percent. The increase was primarily due to higher natural gas purchases in December 2005 as compared to December 2004 and timing of outstanding checks clearing the bank.

The balance of Accrued Taxes was approximately $67.1 million and $13.2 million at December 31, 2005 and 2004, respectively, an increase of approximately $53.9 million. The increase was primarily due to the increased income tax liability associated with the sale of EAPC.

The balance of current Price Risk Management liabilities was approximately $109.5 million and $38.7 million at December 31, 2005 and 2004, respectively, an increase of approximately $70.8 million. The increase was primarily due to higher natural gas prices associated with OERI s short-term physical natural gas sales transactions and associated financial contracts. The volume of OERI s short-term physical natural gas activity and associated financial contracts outstanding at December 31, 2005 remained substantially unchanged from December 31, 2004.

The balance of the Gas Imbalance liability was approximately $36.0 million and $16.3 million at December 31, 2005 and 2004, respectively, an increase of approximately $19.7 million. The Gas Imbalance liability is comprised of planned or managed imbalances related to OERI s business, referred to as park and loan transactions, and pipeline and natural gas liquids imbalances, which are operational imbalances. Operational imbalances were approximately $25.6 million and $13.9 million at December 31, 2005 and 2004, respectively, an increase of approximately $11.7 million or 84.2 percent due to higher natural gas storage imbalances from Enogex s storage fields. Park and loan transactions were approximately $10.2 million and $2.4 million at December 31, 2005 and 2004, respectively, an increase of approximately $7.8 million due to increased natural gas storage obligations from higher natural gas prices from OERI s business activities.

The balance of Accrued Pension and Benefit Obligations was approximately $234.5 million and $197.0 million at December 31, 2005 and 2004, respectively, an increase of approximately $37.5 million or 19.0 percent. The increase was primarily due to an increase in the liability associated with the Company s pension plan due to a decrease in the assumed discount rate. See Note 12 of Notes to Consolidated Financial Statements for a further discussion.

Off-Balance Sheet Arrangements

Off-balance sheet arrangements include any transactions, agreements or other contractual arrangements to which an unconsolidated entity is a party and under which the Company has: (i) any obligation under a guarantee contract having specific characteristics as defined in FASB Interpretation No. 45, Guarantor s Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others (ii) a retained or contingent interest in assets transferred to an unconsolidated entity or similar arrangement that serves as credit, liquidity or market risk support to such entity for such assets; (iii) any obligation, including a contingent obligation, under a contract that would be accounted for as a derivative instrument but is indexed to the Company s own stock and is classified in stockholders equity in the Company s consolidated balance sheet; or (iv) any obligation, including a contingent obligation, arising out of a variable interest as defined in FASB Interpretation No. 46, Consolidation of Variable Interest Entities, an interpretation of Accounting Research Bulletin No. 51, in an unconsolidated entity that is held by, and material to, the Company, where such entity provides financing, liquidity, market risk or credit risk support to, or engages in leasing, hedging or research and development services with, the Company. The Company has the following off-balance sheet arrangements.

Heat Pump Loans

Effective January 1, 2004, OG&E discontinued issuing heat pump loans to customers and all new heat pump loans are now processed and managed by a third party. OG&E continues to service the heat pump loans it repurchased in 2004 in addition to the heat pump loans OG&E sold during 2002. The finance rate on the heat pump loans was based upon market rates and was reviewed and updated periodically. OG&E s heat pump loan balance was approximately $0.7 million and $1.3 million at December 31, 2005 and 2004, respectively, and is included in Accounts Receivable, Net in the Consolidated Balance Sheets.

OG&E sold approximately $8.5 million of its heat pump loans in December 2002 as part of a securitization transaction through OGE Consumer Loan 2002, LLC. The following table contains information related to this securitization.

	2002
Date heat pump loans sold	December 2002
Total amount of heat pump loans sold (in millions)	$ 8.5
Heat pump loan balance at December 31, 2005 (in millions)	$ 2.2
Note interest rate	5.25%
Base servicing fee rate (paid monthly)	0.375%
Trustee/custodian fees (paid quarterly) (in whole dollars)	$ 1,250
Owner trustee fees (paid annually) (in whole dollars)	$ 4,000
Sole director s fee (paid quarterly) (in whole dollars)	$ 1,125

Loss exposure by securitization issue (in millions)	$	0.3

Energy Insurance Bermuda Ltd. Mutual Business Program No. 19

Energy Insurance Bermuda Ltd. (EIB) is incorporated in Bermuda under the Companies Act of 1981, as amended. The Company began participating in EIB through Mutual Business Program No. 19 (MBP 19) in November 1998. The Company terminated the MBP 19 program during the second quarter of 2005, with an effective date of January 31, 2005, and recorded a reduction in operating and maintenance expense of approximately $0.6 million related to this transaction. During the third and fourth quarters of 2005, the Company received approximately $1.4 million related to the dissolution of this program.

OG&E Railcar Leases

See Note 14 of Notes to Consolidated Financial Statements for a discussion of OG&E s railcar lease agreement.

Liquidity and Capital Requirements

The Company s primary needs for capital are related to replacing or expanding existing facilities in OG&E s electric utility business and replacing or expanding existing facilities (including technology) at Enogex. Other working capital requirements are primarily related to maturing debt, operating lease obligations, hedging activities, natural gas storage and delays in recovering unconditional fuel purchase obligations. The Company generally meets its cash needs through a combination of internally generated funds, short-term borrowings (through a combination of bank borrowings and commercial paper) and permanent financings.

Capital requirements and future contractual obligations estimated for the next five years and beyond are as follows:

(In millions)	Total	Less than 1 year	1 - 3 years	3 - 5 years	More than 5 years
OG&E capital expenditures including AFUDC (A)	$ 661.0	$ 237.0	$ 424.0	N/A	N/A
Enogex capital expenditures and acquisitions	114.0	60.0	54.0	N/A	N/A
Other Operations capital expenditures	30.0	10.0	20.0	N/A	N/A
Total capital expenditures	805.0	307.0	498.0	N/A	N/A

Maturities of long-term debt	1,349.4	---	4.0	$ 400.0	$ 945.4
Interest payments on long-term debt	1,168.7	84.5	168.5	138.1	777.6
Pension funding obligations	189.9	90.0	70.7	29.2	N/A
Total capital requirements	3,513.0	481.5	741.2	567.3	1,723.0
Operating lease obligations					
OG&E railcars	56.3	4.3	7.9	7.5	36.6
Enogex noncancellable operating leases	4.6	3.3	1.0	0.2	0.1
Total operating lease obligations	60.9	7.6	8.9	7.7	36.7
Other purchase obligations and commitments					
OG&E cogeneration capacity payments	476.4	98.6	192.5	185.3	N/A
OG&E fuel minimum purchase commitments	832.5	184.3	359.0	202.4	86.8
Other	68.2	7.4	14.9	14.9	31.0
Total other purchase obligations and commitments	1,377.1	290.3	566.4	402.6	117.8
Total capital requirements, operating lease obligations and other purchase obligations and commitments	4,951.0	779.4	1,316.5	977.6	1,877.5
Amounts recoverable through automatic fuel adjustment clause (B)	(1,365.2)	(287.2)	(559.4)	(395.2)	(123.4)
Total, net	$ 3,585.8	$ 492.2	$ 757.1	$ 582.4	$ 1,754.1

(A) Under current environmental laws and regulations, OG&E may be required to spend additional capital expenditures on its coal-fired plants. These expenditures would not begin until the year 2008. The amounts and timing of these expenditures is uncertain at the present time.

(B) Includes expected recoveries of costs incurred for OG&E s railcar operating lease obligations and OG&E s unconditional fuel purchase obligations.

N/A not available

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 automatic fuel adjustment clauses. Accordingly, while the cost of fuel related to operating leases and the vast majority of unconditional fuel purchase obligations of OG&E noted above may increase capital requirements, such costs are recoverable through automatic fuel adjustment clauses and have little, if any, impact on net capital requirements and future contractual obligations. The automatic fuel adjustment clauses are subject to periodic review by the OCC, the APSC and the FERC. See Note 15 of Notes to Consolidated Financial Statements for a discussion of the completed proceedings at the OCC regarding OG&E s gas transportation and storage contract with Enogex.

2005 Capital Requirements and Financing Activities

Total capital requirements, consisting of capital expenditures, maturities of long-term debt, interest payments on long-term debt and pension funding obligations, were approximately $448.8 million and contractual obligations, net of recoveries through automatic fuel adjustment clauses, were approximately $4.3 million resulting in total net capital requirements and contractual obligations of approximately $453.1 million in 2005. Approximately $19.2 million of the 2005 capital requirements were to comply with environmental regulations. This compares to net capital requirements of approximately $840.0 million and net contractual obligations of approximately $4.3 million totaling approximately $844.3 million in 2004, of which approximately $7.8 million was to comply with environmental regulations. During 2005, the

Company s sources of capital were internally generated funds from operating cash flows, short-term borrowings (through a combination of bank borrowings and commercial paper) and proceeds from the sale of assets. The Company uses its commercial paper to fund changes in working capital and as an interim source of financing capital expenditures until permanent financing is arranged. Changes in working capital reflect the seasonal nature of the Company s business, the revenue lag between billing and collection from customers and fuel inventories. See Financial Condition for a discussion of significant changes in net working capital requirements as it pertains to operating cash flow and liquidity.

Discontinued Operations

Also contributing to the liquidity of the Company has been the disposition of certain assets classified as discontinued operations in 2005. During 2005, these dispositions have generated net sales proceeds of approximately $184.7 million. Sales proceeds generated to date have been used to reduce debt at Enogex and commercial paper at the holding company.

Additional asset sales could further contribute to the liquidity of the Company.

Long-term Debt Maturities

Maturities of the Company s long-term debt during the next five years consist of $3.0 million in 2007; $1.0 million in 2008 and $400.0 million in 2010. There are no maturities of the Company s long-term debt in years 2006 or 2009.

Interest Rate Swap Agreements

See Note 10 of Notes to Consolidated Financial Statements for a discussion of the Company s interest rate swap agreements.

Treasury Lock Agreements

See Note 1 of Notes to Consolidated Financial Statements for a discussion of the Company s treasury lock agreements.

Future Capital Requirements

Capital Expenditures

The Company s current 2006 to 2008 construction program includes continued investment in OG&E s and Enogex s assets. To reliably meet the increased electricity needs of OG&E s customers during the foreseeable future, OG&E will continue to invest to maintain the integrity of the delivery system. Approximately $5.0 million of the Company s capital expenditures budgeted for 2006 are to comply with environmental laws and regulations. OG&E plans to continue to invest in its electric system at a level consistent with 2005. These capital expenditures do not include any capital requirements associated with OG&E s proposed wind power project pending approval from the OCC. OG&E has approximately 430 MW s of QF contracts that will expire at the end of 2007, unless extended by OG&E. For one of these QF contracts, OG&E purchases 100 percent of electricity generated by the QF. For the other QF contract, OG&E can purchase up to 17 percent of electricity generated by the QF. In addition, effective September 1, 2004, OG&E entered into a new 15-year power purchase agreement for 120 MW s with PowerSmith Cogeneration Project, L.P. (PowerSmith), in which OG&E purchases 100 percent of electricity generated by PowerSmith. OG&E will continue reviewing all of the supply alternatives to these expiring 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. Accordingly, OG&E will continue to explore opportunities to build or buy power plants in order to serve its native load. As a result of the high volatility of current natural gas prices and the increase in natural gas prices, OG&E will also assess the feasibility of constructing additional base load coal-fired units as well as wind generation facilities.

Refinancing of Long-Term Debt

In August 2005, OG&E filed a Form S-3 Registration Statement to register the sale of up to $400.0 million of OG&E s unsecured debt securities. On October 17, 2005, OG&E paid at maturity its $110 million of 7.125 percent senior notes and redeemed its $110 million of 7.30 percent senior notes due October 15, 2025 at the principal amount plus a $3.6 million premium. The repayments were funded temporarily through the issuance of commercial paper by the Company and OG&E and borrowings under existing credit agreements which OG&E replaced with the proceeds from the issuance of $110 million of 5.15 percent senior notes and $110 million of 5.75 percent senior notes in January 2006.

Pension and Postretirement Benefit Plans

During 2005, actual asset returns for the Company s defined benefit pension plan were positively affected by growth in the equity markets; however, the growth in 2005 was not as strong as the growth in the equity markets in 2004. At December 31, 2005, approximately 59 percent of the pension plan assets are invested in listed common stocks with the balance invested in corporate debt and U.S. Government securities. In 2005, asset returns on the pension plan were approximately 6.20 percent as compared to approximately 12.51 percent in 2004. During the same time, corporate bond yields, which are used in determining the discount rate for future pension obligations, have continued to decline.

Contributions to the pension plan decreased from approximately $69.0 million in 2004 to approximately $32.0 million in 2005. This decrease in pension plan funding in 2005 was due to the fact that in prior years additional amounts were contributed to the pension plan to maintain an adequate funded status. During 2006, the Company may contribute up to $90 million to the pension plan. The level of funding is dependent on returns on plan assets and future discount rates. Higher returns on plan assets and increases in discount rates will reduce funding requirements to the plan. Legislation is before Congress that if passed would change the funding requirements for defined benefit plans. The proposed legislation would generally provide employers less funding flexibility and require a higher funding level than required under current regulations. Management will continue to monitor the outcome of the legislation.

As discussed in Note 12 of Notes to Consolidated Financial Statements, in 2000 the Company made several changes to its pension plan, including the adoption of a cash balance benefit feature for employees hired after January 31, 2000. The cash balance plan may provide lower post-employment pension benefits to employees, which could result in less pension expense being recorded. Over the near term, the Company s cash requirements for the plan are not expected to be materially different than the requirements existing prior to the plan changes. However, as the population of employees included in the cash balance plan feature increases, the Company s cash requirements should decrease and will be much less sensitive to changes in discount rates.

During 2005 and 2004, the Company made contributions to the pension plan and the restoration of retirement income plan that exceeded amounts previously recognized as net periodic pension expense and recorded a net prepaid benefit obligation at December 31, 2005 and 2004 of approximately $88.9 million and $92.0 million, respectively. At December 31, 2005 and 2004, the Company s projected pension benefit obligation exceeded the fair value of the pension plan assets and the restoration of retirement income plan assets by approximately $154.6 million and $123.3 million, respectively. As a result of recording a prepaid benefit obligation and having a funded status where the projected benefit obligations exceeded the fair value of plan assets, provisions of SFAS No. 87, Employers Accounting for Pensions, required the recognition of an additional minimum liability in the amount of approximately $181.4 million and $156.6 million, respectively, at December 31, 2005 and 2004. The offset of this entry was an intangible asset and Accumulated Other Comprehensive Income, net of a deferred tax asset; therefore, this adjustment did not impact the results of operations in 2005 or 2004 and did not require a usage of cash and is therefore excluded from the Consolidated Statements of Cash Flows. The amount recorded as an intangible asset equaled the unrecognized prior service cost with the remainder recorded in Accumulated Other Comprehensive Income. The amount in Accumulated Other Comprehensive Income represents a net periodic pension cost to be recognized in the Consolidated Statements of Income in future periods.

Security Ratings

	Moody s	Standard & Poor s	Fitch s
OG&E Senior Notes	A2	BBB+	AA-
Enogex Notes	Baa3	BBB+	BBB
OGE Energy Corp. Senior Notes	Baa1	BBB	A
OGE Energy Corp. Commercial Paper	P2	A2	F1

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, 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.

Future Sources of Financing

Management expects that internally generated funds, long and short-term debt and proceeds from the sales of common stock pursuant to the Company s Automatic Dividend Reinvestment and Stock Purchase Plan will be adequate over the next three years to meet anticipated cash needs. 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

See Note 11 of Notes to Consolidated Financial Statements for a discussion of the Company s short-term debt activity.

Common Stock

See Note 7 of Notes to Consolidated Financial Statements for a discussion of the Company s common stock activity.

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 affect on the Company s Consolidated Financial Statements particularly as they relate to pension expense and impairment estimates. 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 is in the valuation of pension plan assumptions, impairment estimates, contingency reserves, accrued removal obligations, regulatory assets and liabilities, unbilled revenue for OG&E, operating revenues for Enogex, natural gas purchases for Enogex, the allowance for uncollectible accounts receivable, the valuation of energy purchase and sale contracts and fair value and cash flow hedging policies. The selection, application and disclosure of the following critical accounting estimates have been discussed with the Company s audit committee.

Consolidated (including Electric Utility and Natural Gas Pipeline Segments)

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 12 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 plan. The following table indicates the sensitivity of the pension plans funded status to these variables.

	Change		Impact on Funded Status
Actual plan asset returns	+/-	5 percent	+/- $21.2 million
Discount rate	+/-	0.25 percent	+/- $18.6 million
Contributions	+	$10.0 million	+ $10.0 million
Expected long-term return on plan assets	+/-	1 percent	None

The Company assesses potential impairments of assets or asset groups when there is evidence that events or changes in circumstances require an analysis of the recoverability of an asset or asset group. For purposes of recognition and measurement of an impairment loss, a long-lived asset or assets shall be grouped with other assets and liabilities at the lowest level for which identifiable cash flows are largely independent of the cash flows of other assets and liabilities. Estimates of future cash flows used to test the recoverability of a long-lived asset or asset group shall include only the future cash flows

25

(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 or asset group. The fair value of these assets is based on third-party evaluations, prices for similar assets, historical data and projected cash flow. 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. Enogex expects to continue to evaluate the strategic fit and financial performance of each of its assets in an effort to ensure a proper economic allocation of resources. The magnitude and timing of any potential impairment or gain on the disposition of any assets have not been included in the 2006 earnings guidance.

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

In March 2005, the FASB issued FASB Interpretation No. 47, Accounting for Conditional Asset Retirement Obligations, in which an entity is required to recognize a liability for the fair value of an asset retirement obligation (ARO) that is conditional on a future event if the liability s fair value can be reasonably estimated. The fair value of a liability for the conditional ARO should be recognized when incurred. Uncertainty surrounding the timing and method of settlement of a conditional ARO should be factored into the measurement of the liability when sufficient information exists. However, in some cases, there is insufficient information to estimate the fair value of an ARO. In these cases, the liability should be initially recognized in the period in which sufficient information is available for an entity to make a reasonable estimate of the liability s fair value. FIN 47 required both recognition of a cumulative change in accounting principle and disclosure of the liability on a pro forma basis for transition purposes. FIN 47 is effective no later than the end of fiscal years ending after December 15, 2005. The Company adopted this new interpretation effective December 31, 2005 which resulted in an ARO of approximately $2.5 million being recorded for power plant structure legal obligations associated with various removal items, of which approximately $0.4 million is the ARO and approximately $2.1 million are cumulative accretion costs. Beginning January 1, 2006, the Company will amortize the remaining value of the related ARO assets over their remaining lives ranging from 20 to 50 years. The cumulative accretion costs of approximately $2.1 million that are included in the ARO were reclassified from the regulatory liability account associated with Accrued Removal Obligations to Asset Retirement Obligations on the Consolidated Balance Sheet and, as a result, there was no earnings impact from a cumulative effect adjustment due to a change in accounting principle. In addition, the cumulative depreciation expense for the ARO assets of approximately $0.2 that would have been recorded for the time period from the date the liability would have been originally recorded under FIN 47 was also reclassified from the regulatory liability account to accumulated depreciation for the ARO assets with no earnings impact. At December 31, 2003 and 2004, the pro forma amount of the ARO would have been approximately $2.4 million. The Company has identified other ARO s that have not been recorded because the Company determined that these assets have indefinite lives primarily related to OG&E s power plant sites and Enogex s processing plants.

OG&E and Enogex engage in cash flow and fair value hedge transactions to modify the rate composition of the debt portfolio. Enogex also engages in cash flow and fair value hedge transactions to manage commodity risk. Enogex may hedge its forward exposure to manage changes in commodity prices. Anticipated transactions are documented as cash flow hedges pursuant to SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities, as amended, hedging requirements and are executed based upon management established price targets. During 2003, OERI also utilized fair value hedges under SFAS No. 133 to manage commodity price exposure for natural gas storage inventory. However, during 2004 and 2005, OERI decided not to utilize hedge accounting under SFAS No. 133 for natural gas storage inventory. 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. OG&E and Enogex have entered into interest rate swap agreements and treasury lock agreements relating to managing interest rate exposure on the debt portfolio or anticipated debt issuances to modify the interest rate exposure on fixed rate debt issues. These interest rate swaps and treasury lock agreements qualify as fair value or cash flow hedges under SFAS No. 133. The objective of the interest rate swaps was to achieve a lower cost of debt and to raise the percentage of total corporate long-term floating rate debt to reflect a level more in line with industry standards. The objective of the treasury lock agreements was to protect against the variability of future payments of interest expense of debt that was issued by OG&E in January 2006.

Electric Utility Segment

OG&E, as a regulated utility, is subject to the accounting principles prescribed by the SFAS No. 71, Accounting for the Effects of Certain Types of Regulation. SFAS No. 71 provides 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.

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, 2005, 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 approximately $0.4 million. At December 31, 2005 and 2004, Accrued Unbilled Revenues were approximately $41.8 million and $45.5 million, respectively. The estimates that management uses in this calculation could vary from the actual amounts to be paid by customers.

Customer balances are generally written off if not collected within six months after the final billing date. The allowance for uncollectible accounts receivable 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. At December 31, 2005, if the provision rate were to increase or decrease by 10 percent, this would cause a change in the uncollectible expense recognized of approximately $0.2 million. The allowance for uncollectible accounts receivable is a reduction to Accounts Receivable on the Consolidated Balance Sheets and is included in Other Operation and Maintenance Expense on the Consolidated Statements of Income. The allowance for uncollectible accounts receivable was approximately $2.5 million and $2.7 million at December 31, 2005 and 2004, respectively.

Natural Gas Pipeline Segment

Operating revenues for transportation, storage, gathering and processing services for Enogex are recorded each month based on the current month s estimated volumes, 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 natural gas liquids 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.

Estimates for gas purchases are based on sales 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.

OERI s activities include the marketing of natural gas and natural gas liquids. The vast majority of these contracts expire within three years, which is when the cash aspect of the transactions will be realized. A substantial portion of these contracts qualify as derivatives under SFAS No. 133 and are marked-to-market with offsetting gains and losses recorded in earnings. In nearly all cases, independent market prices are obtained and compared to the values used for this mark-to-market valuation, and an oversight group outside of the marketing organization monitors all modeling methodologies and assumptions. The recorded value of the energy contracts may change significantly in the future as the market price for the commodity changes, but the value is still subject to the risk loss limitations provided under the Company s risk policies. The Company utilizes models to estimate the fair value of its energy contracts including derivatives that do not have an independent market price. At December 31, 2005, unrealized mark-to-market gains were approximately $5.7 million, which included approximately $0.7 million of unrealized mark-to-market gains that were calculated utilizing models. At December 31, 2005, a price movement of one percent for prices verified by independent parties would result in changes in unrealized mark-to-market gains of approximately $0.1 million and a price movement of five percent on model-based prices would

27

result in changes in unrealized mark-to-market gains of approximately $0.1 million. Energy contracts are presented in Price Risk Management assets and liabilities on the Consolidated Balance Sheets and in Operating Revenues on the Consolidated Statements of Income.

Natural gas inventory used in Enogex s business is recorded at the lower of cost or market. In order to minimize risk, OERI enters into contracts or hedging instruments to hedge the fair value of this inventory. OERI has elected not to designate inventory hedging contracts as fair value or cash flow hedges under SFAS No. 133. The fair value of the hedging instruments is recorded on the books of OERI as a Price Risk Management asset or liability with an offsetting gain or loss recorded in current earnings. As part of its recurring business activity, OERI injects and withdraws natural gas under the terms of storage capacity contracts. The amount of Enogex s natural gas inventory was approximately $35.7 million and $46.8 million at December 31, 2005 and 2004, respectively. Natural gas storage inventory is presented in Fuel Inventories on the Consolidated Balance Sheets and in Cost of Goods Sold on the Consolidated Statements of Income.

The allowance for uncollectible accounts receivable 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 the Company believes the required payment 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 allowance for uncollectible accounts receivable for the Natural Gas Pipeline segment was approximately $1.2 million and $1.8 million at December 31, 2005 and 2004, respectively.

Accounting Pronouncements

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

Electric Competition; Regulation

OG&E and Enogex have been and will continue to be affected by competitive changes to the utility and energy industries. Significant changes already have occurred and additional changes are being proposed to the wholesale electric market. Although retail restructuring efforts in Oklahoma and Arkansas have been postponed for the time being, if such efforts were renewed, retail competition and the unbundling of regulated energy service could have a significant financial impact on the Company due to an impairment of assets, a loss of retail customers, lower profit margins and/or increased costs of capital. Any such restructuring could have a significant impact on the Company s consolidated financial position, results of operations and cash flows. The Company cannot predict when it will be subject to changes in legislation or regulation, nor can it predict the impact of these changes on the Company s consolidated financial position, results of operations or cash flows. The Company believes that the prices for electricity and the quality and reliability of the Company s service currently place us in a position to compete effectively in the energy market. These developments at the federal and state levels as well as pending regulatory matters affecting the Company are described in more detail in Note 15 of Notes to Consolidated Financial Statements.

Commitments and Contingencies

In the normal course of business, the Company is confronted with issues or events that may result in a contingent liability. These generally relate to lawsuits, claims made by third parties, environmental actions or the action of various regulatory agencies. Management consults with legal counsel and other appropriate experts to assess the claim. If in management s opinion, the Company has incurred a probable loss as set forth by accounting principles generally accepted in the United States, an estimate is made of the loss and the appropriate accounting entries are reflected in the Company s Consolidated Financial Statements. Management, after consultation with legal counsel, does not currently anticipate that liabilities arising out of these pending or threatened lawsuits, claims and contingencies will have a material adverse effect on the Company s consolidated financial position, results of operations or cash flows. See Note 14 of Notes to Consolidated Financial Statements for a discussion of the Company s commitments and contingencies.

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, commodity prices, commodity price volatilities and interest rates. The Company is exposed to commodity price and commodity price volatility risks in its operations. The Company s exposure to changes in interest rates relates primarily to short-term variable-rate debt, interest rate swap agreements and commercial paper. The Company also engages in price risk management activities for both trading and non-trading purposes.

Risk Committees and Oversight

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

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

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

Risk Policies

The Company utilizes risk policies to control the amount of market risk exposure. These policies, which include value-at-risk (VaR) limits, position limits, tenor limits and stop loss limits, are designed to provide the Audit Committee of the 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 risk management are being followed.

Interest Rate Risk

The Company s exposure to changes in interest rates relates primarily to short-term debt, interest rate swap agreements and commercial paper. The Company manages its interest rate exposure by limiting its variable rate debt to a certain percentage of total capitalization and by monitoring the effects of market changes in interest rates. The Company utilizes interest rate derivatives to alter interest rate exposure in an attempt to reduce interest expense related to existing debt issues. Interest rate derivatives are used solely to modify interest rate exposure and not to modify the overall leverage of the debt portfolio.

Fair Value Hedges

At December 31, 2005, the Company had no outstanding interest rate swap agreements. At December 31, 2004, the Company had three outstanding interest rate swap agreements that qualified as fair value hedges: (i) OG&E entered into an interest rate swap agreement, effective March 30, 2001, to convert $110.0 million of 7.30 percent fixed rate debt due October 15, 2025, to a variable rate based on the three month London InterBank Offering Rate (LIBOR) and (ii) Enogex entered into two separate interest rate swap agreements, effective July 15, 2002 and October 24, 2002, to convert a total of $200.0 million ($100.0 million for each interest rate swap agreement) of 8.125 percent fixed rate debt due January 15, 2010, to a variable rate based on the six month LIBOR in arrears. The objective of these interest rate swaps was to achieve a lower cost of debt and to raise the percentage of total corporate long-term floating rate debt to reflect a level more in line with industry standards. These interest rate swaps qualified as fair value hedges under SFAS No. 133 and met all of the requirements for a determination that there was no ineffective portion as allowed by the shortcut method under SFAS No. 133.

On April 1, 2005, Enogex terminated two interest rate swap agreements (with a total notional amount of $200 million) and received approximately $0.2 million related to this transaction. Since inception of the Enogex interest rate swap agreements, which converted $200 million of 8.125 percent fixed rate debt due January 15, 2010 to a floating rate based upon the three and six month LIBOR, the Company has paid approximately $81.3 million in interest and has received approximately $29.9 million related to these agreements. The effective interest rate until maturity will be approximately 7.67 percent on this long-term debt.

On September 1, 2005, the counterparty to OG&E s interest rate swap agreement exercised its right to change the termination date of the interest rate swap agreement from October 15, 2025 to October 15, 2005 in conjunction with the early redemption of long-term debt discussed in Note 10 of Notes to Consolidated Financial Statements. On October 17, 2005, OG&E received approximately $5.3 million related to the termination of its interest rate agreement of which approximately $1.7 million is related to interest received and approximately $3.6 million is related to canceling the interest rate swap agreement, which will be amortized over the life of the long-term debt OG&E issued in January 2006.

At December 31, 2004, the fair values pursuant to the interest rate swaps were approximately $7.9 million and the hedges were classified as Deferred Charges and Other Assets Price Risk Management in the Consolidated Balance Sheet. A corresponding net increase of approximately $7.9 million was reflected in Long-Term Debt at December 31, 2004 as these fair value hedges were effective at December 31, 2004.

Cash Flow Hedges of Interest Rates

OG&E entered into two separate treasury lock agreements, effective November 14, 2005 and November 16, 2005, respectively, to hedge approximately $50.0 million each of future interest payments of long-term debt that was issued in January 2006. These treasury locks were terminated in early December due to the lack of an OCC order in OG&E s rate case at the time. OG&E entered into two separate treasury lock agreements, effective December 28, 2005, to hedge approximately $50.0 million each of future interest payments of long-term debt that was issued in January 2006. These treasury locks were terminated on January 6, 2006 after OG&E issued long-term debt. OG&E received less than $0.1 million related to the termination of the aforementioned treasury lock agreements.

The fair value of the Company s long-term debt is based on quoted market prices and management s estimate of current rates available for similar issues with similar maturities. At December 31, 2005, the Company had no outstanding interest rate swap agreements. The following table shows the Company s long-term debt maturities and the weighted-average interest rates by maturity date.

(Dollars in millions)	2006	2007	2008	2009	2010	Thereafter	Total	12/31/05 Fair Value
Fixed rate debt (A)								
Principal amount	$ ---	$ 3.0	$ 1.0	$ ---	$ 400.0	$ 810.0	$ 1,214.0	$ 1,273.4
Weighted-average interest rate	---	8.28%	7.07%	---	8.13%	6.05%	6.74%	---
Variable rate debt (B)								
Principal amount	---	---	---	---	---	$ 135.4	$ 135.4	$ 135.4
Weighted-average interest rate	---	---	---	---	---	2.62%	2.62%	---

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

(B) A hypothetical change of 100 basis points in the underlying variable interest rate would increase interest expense by approximately $1.4 million annually.

The Company s price risk management assets and liabilities as of December 31, 2005 were as follows:

(Dollars in millions)	Commodity	Notional Volume (MMBtu)	Maturity	Fair Value
TRADING				
Price Risk Management Assets				
Physical Purchases	Natural Gas	59.4	2006	$ 50.3
Physical Purchases	Natural Gas	2.7	2007	8.5
Total Physical Purchases				58.8
Physical Sales	Natural Gas	(53.6)	2006	22.4
Long Physical Options	Natural Gas	2.2	2006	0.1
Short Physical Options	Natural Gas	(54.9)	2006	3.3
Long Financial Swaps (excluding basis)	Natural Gas	3.1	2006	5.6
Short Financial Swaps (excluding basis)	Natural Gas	(5.7)	2006	1.0
Short Financial Options	Natural Gas	(2.0)	2006	0.8
Long Basis Positions	Natural Gas	42.7	2006	0.1
Short Basis Positions	Natural Gas	(49.8)	2006	32.2
Short Basis Positions	Natural Gas	(1.2)	2007	0.5
Total Short Basis Positions				32.7
				$ 124.8
TRADING				
Price Risk Management Liabilities				
Physical Purchases	Natural Gas	59.4	2006	$ 26.1
Physical Sales	Natural Gas	(53.6)	2006	37.4
Physical Sales	Natural Gas	(2.5)	2007	10.3
Total Physical Sales				47.7
Short Physical Options	Natural Gas	(54.9)	2006	1.3
Long Financial Swaps (excluding basis)	Natural Gas	3.1	2006	3.3
Short Financial Swaps (excluding basis)	Natural Gas	(5.7)	2006	13.5
Long Financial Options	Natural Gas	2.5	2006	1.3
Long Basis Positions	Natural Gas	42.7	2006	25.7
Long Basis Positions	Natural Gas	0.9	2007	0.4
Total Long Basis Positions				26.1
Short Basis Positions	Natural Gas	(49.8)	2006	0.4
				$ 119.7
NON-TRADING				
Price Risk Management Assets				
Long Financial Swaps (excluding basis)	Natural Gas	0.5	2006	$ 0.1
Long Basis Positions	Natural Gas	0.6	2006	0.1
Short Basis Positions	Natural Gas	(0.3)	2006	0.5
				$ 0.7
NON-TRADING				
Price Risk Management Liabilities				
Long Financial Swaps (excluding basis)	Natural Gas	0.5	2006	$ 0.3

Long Basis Positions	Natural Gas	0.6	2006	0.2
				$ 0.5

31

The valuation of the Company s price risk management assets and liabilities were determined primarily 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 and the potential impact of liquidating the position in an orderly manner over a reasonable period of time.

Commodity Price Risk

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

Trading Activities

The trading activities are conducted throughout the year subject to daily and monthly trading stop loss limits of $2.5 million. The daily loss exposure from trading activities is measured primarily using VaR, which estimates the potential losses the trading activities could incur over a specified time horizon and confidence level. The VaR limit for the Company s trading activities, assuming a one day time horizon and 95 percent confidence level, is $1.5 million. These limits are designed to mitigate the possibility of trading activities having a material adverse effect on the Company s operating income.

A sensitivity analysis has been prepared to estimate the Company s exposure to market risk created by trading activities. The value of trading positions is a summation of the fair values calculated for each commodity by valuing each net position at quoted market prices. Market risk is estimated as the potential loss in fair value resulting from a hypothetical 10 percent adverse change in such prices over the next 12 months. The result of this analysis, which may differ from actual results, is as follows for 2005.

(In millions)	Trading
Commodity market risk, net	$ 1.0

Non-Trading Activities

The prices of natural gas, natural gas liquids and natural gas liquids processing spreads are subject to fluctuations resulting from changes in supply and demand. The changes in these prices have a direct effect on the compensation received by the Company for operating some of its assets. To partially reduce non-trading commodity price risk, the Company hedges, through the utilization of derivatives and other forward transactions, the effects these market fluctuations have on the operating income of the Company. Because the commodities covered by these hedges are substantially the same commodities that the Company buys and sells in the physical market, no special studies other than monitoring the degree of correlation between the derivative and cash markets are deemed necessary.

A sensitivity analysis has been prepared to estimate the Company s exposure to the market risk of the Company s non-trading activities. The Company s daily net commodity position consists of natural gas inventories, commodity purchase and sales contracts, financial and commodity derivative instruments and anticipated natural gas processing spreads and fuel recoveries. Quoted market prices are not available for all of the Company s non-trading positions, therefore, the value of non-trading positions is a summation of the forecasted values calculated for each commodity based upon internally generated forecast prices. Market risk is estimated as the potential loss in fair value resulting from a hypothetical 10 percent adverse change in such prices over the next 12 months. The result of this analysis, which may differ from actual results, is as follows for 2005.

(In millions)	Non-Trading
Commodity market risk, net	$ 6.9

The Company may designate certain derivative instruments for the purchase or sale of physical commodities, purchase or sale of electric power and fuel procurement as normal purchases and normal sales contracts under the provisions of SFAS No. 133. Normal purchases and normal sales contracts are not recorded in Price Risk Management assets or liabilities in the Consolidated Balance Sheets and earnings recognition is recorded in the period in which physical delivery of the commodity occurs. The Company applies normal purchases and normal sales to commodity contracts for the sale of

natural gas liquids produced by its subsidiary, Enogex Products Corporation, to electric power contracts by OG&E and for fuel procurement by OG&E.

Credit Risk

Credit risk includes the risk that counterparties that owe us money or energy will breach their obligations. If the counterparties to these arrangements fail to perform, we may be forced to enter into alternative arrangements. In that event, our financial results could be adversely affected and we could incur losses.

For OG&E, new business customers are required to provide a security deposit in the form of cash, a bond or irrevocable letter of credit which is refunded when the account is closed. New residential customers, whose outside credit scores indicate risk, are required to provide a security deposit which is refunded after 12 months of good payment history per the regulatory rules. The payment behavior of all existing customers is monitored and if the payment behavior indicates sufficient risk per the regulatory rules, customers will be required to provide a security deposit.

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 condition (including credit rating), collateral requirements under certain circumstances and the use of standardized agreements which provide for the netting of cash flows associated with a single counterparty. Enogex also monitors the financial condition of existing counterparties on an ongoing basis.

Currency Risk

The Company is exposed to currency risk from the Canadian dollar. This exposure is created by infrequent energy transactions entered into by OERI. Currency risk associated with this exposure is not material.

Financial Statements and Supplementary Data.

OGE ENERGY CORP.

CONSOLIDATED BALANCE SHEETS

December 31 *(In millions)*	**2005**	2004
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	**$ 26.4**	$ 11.1
Accounts receivable, net	**591.4**	484.5
Accrued unbilled revenues	**41.8**	45.5
Fuel inventories	**63.6**	89.0
Materials and supplies, at average cost	**56.5**	53.2
Price risk management	**116.5**	54.3
Gas imbalances	**32.0**	99.8
Accumulated deferred tax assets	**14.3**	13.7
Fuel clause under recoveries	**101.1**	54.3
Recoverable take or pay gas charges	**4.9**	17.0

Prepayments and other	**25.1**	25.4
Current assets of discontinued operations	**---**	7.2
Total current assets	**1,073.6**	955.0
OTHER PROPERTY AND INVESTMENTS, at cost	**29.2**	31.4
PROPERTY, PLANT AND EQUIPMENT		
In service	**6,056.5**	5,811.0
Construction work in progress	**102.2**	110.4
Other	**3.1**	1.1
Total property, plant and equipment	**6,161.8**	5,922.5
Less accumulated depreciation	**2,594.4**	2,474.1
Net property, plant and equipment	**3,567.4**	3,448.4
In service of discontinued operations	**---**	151.4
Less accumulated depreciation	**---**	18.8
Net property, plant and equipment of discontinued operations	**---**	132.6
Net property, plant and equipment	**3,567.4**	3,581.0
DEFERRED CHARGES AND OTHER ASSETS		
Income taxes recoverable from customers, net	**32.8**	30.9
Intangible asset - unamortized prior service cost	**32.8**	38.0
Prepaid benefit obligation	**90.2**	92.7
Price risk management	**9.0**	16.4
McClain Plant deferred expenses	**24.9**	11.0
Unamortized loss on reacquired debt	**21.3**	21.0
Unamortized debt issuance costs	**8.1**	8.7
Other	**9.6**	12.1
Deferred charges and other assets of discontinued operations	**---**	4.7
Total deferred charges and other assets	**228.7**	235.5
TOTAL ASSETS	**$ 4,898.9**	$ 4,802.9

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

34

OGE ENERGY CORP.

CONSOLIDATED BALANCE SHEETS (Continued)

December 31 *(In millions)*	**2005**	2004
LIABILITIES AND STOCKHOLDERS EQUITY		
CURRENT LIABILITIES		
Short-term debt	**$ 30.0**	$ 125.0
Accounts payable	**510.4**	470.3
Dividends payable	**30.1**	29.9
Customers deposits	**47.8**	48.3
Accrued taxes	**67.1**	13.2
Accrued interest	**31.9**	32.8
Tax collections payable	**8.7**	7.2
Accrued vacation	**18.5**	17.9
Long-term debt due within one year	**---**	34.3
Price risk management	**109.5**	38.7
Gas imbalances	**36.0**	16.3
Provision for payments of take or pay gas	**8.9**	21.0
Accrued compensation	**21.5**	19.4
Other	**30.2**	27.3
Current liabilities of discontinued operations	**---**	9.6
Total current liabilities	**950.6**	911.2
LONG-TERM DEBT		
Long-term debt	**1,350.8**	1,359.1
Long-term debt of discontinued operations	**---**	65.0
Total long-term debt	**1,350.8**	1,424.1
COMMITMENTS AND CONTINGENT LIABILITIES (NOTE 14)		
DEFERRED CREDITS AND OTHER LIABILITIES		
Accrued pension and benefit obligations	**234.5**	197.0
Accumulated deferred income taxes	**807.1**	784.2
Accumulated deferred investment tax credits	**31.7**	36.8
Accrued removal obligations, net	**114.2**	122.2
Price risk management	**10.7**	3.5
Asset retirement obligation	**3.6**	1.1
Other	**19.9**	18.9
Deferred credits and other liabilities of discontinued operations	**---**	18.3
Total deferred credits and other liabilities	**1,221.7**	1,182.0
STOCKHOLDERS EQUITY		
Common stockholders equity	**715.5**	700.8
Retained earnings	**750.5**	659.8
Accumulated other comprehensive loss, net of tax	**(90.2)**	(75.0)
Total stockholders equity	**1,375.8**	1,285.6
TOTAL LIABILITIES AND STOCKHOLDERS EQUITY	**$ 4,898.9**	$ 4,802.9

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

OGE ENERGY CORP.

CONSOLIDATED STATEMENTS OF CAPITALIZATION

December 31 *(In millions)*		**2005**	2004
STOCKHOLDERS EQUITY			
Common stock, par value $0.01 per share; authorized 125.0 shares; and outstanding 90.6 and 90.0 shares, respectively		**$ 0.9**	$ 0.9
Premium on capital stock		**714.6**	699.9
Retained earnings		**750.5**	659.8
Accumulated other comprehensive loss, net of tax		**(90.2)**	(75.0)
Total stockholders equity		**1,375.8**	1,285.6
LONG-TERM DEBT			
SERIES	DATE DUE		
Senior Notes-OGE Energy Corp.			
5.00 %	Senior Notes, Series Due November 15, 2014	**100.0**	100.0
Unamortized discount		**(0.8)**	(0.9)
Senior Notes-OG&E			
7.125 %	Senior Notes, Series Due October 15, 2005	**---**	110.0
6.50 %	Senior Notes, Series Due July 15, 2017	**125.0**	125.0
Variable%	Senior Notes, Series Due October 15, 2025	**---**	114.0
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
Other bonds-OG&E			
1.56% - 3.71%	Garfield Industrial Authority, January 1, 2025	**47.0**	47.0
1.80% - 3.70%	Muskogee Industrial Authority, January 1, 2025	**32.4**	32.4
1.74% - 3.63%	Muskogee Industrial Authority, June 1, 2027	**56.0**	56.0
Other long-term debt (NOTE 11)		**220.0**	---
Unamortized discount		**(1.4)**	(2.2)
Enogex Notes Continuing Operations			
6.81% - 6.99%	Medium-Term Notes, Series Due 2005	**---**	34.3
8.28%	Medium-Term Notes, Series Due 2007	**3.0**	3.0
7.07%	Medium-Term Notes, Series Due 2008	**1.0**	1.0
8.125%	Medium-Term Notes, Series Due 2010	**400.0**	200.0
Variable %	Medium-Term Notes, Series Due 2010	**---**	203.9
Unamortized swap monetization		**3.6**	4.9
Enogex Notes Discontinued Operations			
7.15%	Medium-Term Notes, Series Due 2018	**---**	65.0
Total long-term debt		**1,350.8**	1,458.4
Less long-term debt due within one year		**---**	34.3
Total long-term debt (excluding long-term debt due within one year)		**1,350.8**	1,424.1

Total Capitalization	**$ 2,726.6**	$ 2,709.7

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

36

OGE ENERGY CORP.

CONSOLIDATED STATEMENTS OF INCOME

Year ended December 31 *(In millions, except per share data)*	**2005**	2004	2003
OPERATING REVENUES			
Electric Utility operating revenues	**$ 1,720.7**	$ 1,578.1	$ 1,517.1
Natural Gas Pipeline operating revenues	**4,227.5**	3,326.3	2,240.3
Total operating revenues	**5,948.2**	4,904.4	3,757.4
COST OF GOODS SOLD (exclusive of depreciation shown below)			
Electric Utility cost of goods sold	**946.6**	864.7	792.7
Natural Gas Pipeline cost of goods sold	**4,016.5**	3,098.4	2,048.9
Total cost of goods sold	**4,963.1**	3,963.1	2,841.6
Gross margin on revenues	**985.1**	941.3	915.8
Other operation and maintenance	**398.8**	388.0	367.9
Depreciation	**186.1**	175.0	173.6
Impairment of assets	**---**	7.8	10.2
Taxes other than income	**69.7**	66.7	66.2
OPERATING INCOME	**330.5**	303.8	297.9
OTHER INCOME (EXPENSE)			
Other income	**0.2**	11.8	2.0
Other expense	**(6.0)**	(5.1)	(7.6)
Net other income (expense)	**(5.8)**	6.7	(5.6)
INTEREST INCOME (EXPENSE)			
Interest income	**3.5**	4.9	1.3
Interest on long-term debt	**(80.0)**	(69.4)	(70.1)
Interest expense unconsolidated affiliate	**---**	(13.7)	(17.3)
Allowance for borrowed funds used during construction	**2.2**	1.7	0.5
Interest on short-term debt and other interest charges	**(12.5)**	(9.4)	(5.4)
Net interest expense	**(86.8)**	(85.9)	(91.0)
INCOME FROM CONTINUING OPERATIONS BEFORE TAXES	**237.9**	224.6	201.3
INCOME TAX EXPENSE	**71.8**	77.1	70.8
INCOME FROM CONTINUING OPERATIONS BEFORE CUMULATIVE EFFECT OF CHANGE IN ACCOUNTING			

PRINCIPLE	**166.1**	147.5	130.5
DISCONTINUED OPERATIONS (NOTE 4)			
Income from discontinued operations	**76.2**	9.4	9.8
Income tax expense	**31.3**	3.4	5.1
Income from discontinued operations	**44.9**	6.0	4.7
INCOME BEFORE CUMULATIVE EFFECT OF CHANGE IN ACCOUNTING PRINCIPLE	**211.0**	153.5	135.2
CUMULATIVE EFFECT ON PRIOR YEARS OF CHANGE IN ACCOUNTING PRINCIPLE, net of tax of $3.4	**---**	---	(5.4)
NET INCOME	**$ 211.0**	$ 153.5	$ 129.8
BASIC AVERAGE COMMON SHARES OUTSTANDING	**90.3**	88.0	81.8
DILUTED AVERAGE COMMON SHARES OUTSTANDING	**90.8**	88.5	82.1
BASIC EARNINGS (LOSS) PER AVERAGE COMMON SHARE			
Income from continuing operations	**$ 1.84**	$ 1.67	$ 1.60
Income from discontinued operations, net of tax	**0.50**	0.07	0.06
Loss from cumulative effect of accounting change, net of tax	**---**	---	(0.07)
NET INCOME	**$ 2.34**	$ 1.74	$ 1.59
DILUTED EARNINGS (LOSS) PER AVERAGE COMMON SHARE			
Income from continuing operations	**$ 1.83**	$ 1.66	$ 1.59
Income from discontinued operations, net of tax	**0.49**	0.07	0.06
Loss from cumulative effect of accounting change, net of tax	**---**	---	(0.07)
NET INCOME	**$ 2.32**	$ 1.73	$ 1.58
DIVIDENDS DECLARED PER SHARE	**$ 1.33**	$ 1.33	$ 1.33

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

37

OGE ENERGY CORP.

CONSOLIDATED STATEMENTS OF RETAINED EARNINGS

Year ended December 31 *(In millions)*	**2005**	2004	2003
BALANCE AT BEGINNING OF PERIOD	**$ 659.8**	$ 623.9	$ 604.7
ADD: Net income	**211.0**	153.5	129.8
Total	**870.8**	777.4	734.5
DEDUCT: Dividends declared on common stock	**120.3**	117.6	110.6
BALANCE AT END OF PERIOD	**$ 750.5**	$ 659.8	$ 623.9

OGE ENERGY CORP.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Year ended December 31 *(In millions)*	**2005**	2004	2003
Net income	**$ 211.0**	$ 153.5	$ 129.8
Other comprehensive income (loss), net of tax:			
Minimum pension liability adjustment [($30.0), ($21.2) and $23.8 pre-tax, respectively]	**(18.4)**	(13.0)	14.6
Deferred hedging gains (losses) [$4.7, ($1.1) and $1.5 pre-tax, respectively]	**2.9**	(0.7)	0.9
(Reversal of unrealized gains) unrealized gains on available-for-sale securities [($0.6) and $0.6 pre-tax, respectively]	**---**	(0.4)	0.4
Settlement and amortization of cash flow hedge [$0.5 and ($4.0) pre-tax, respectively]	**0.3**	(2.5)	---
Total other comprehensive income (loss), net of tax	**(15.2)**	(16.6)	15.9
Total comprehensive income	**$ 195.8**	$ 136.9	$ 145.7

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

OGE ENERGY CORP.

CONSOLIDATED STATEMENTS OF CASH FLOWS

Year ended December 31 *(In millions)*	**2005**	2004	2003
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income from continuing operations	**$ 166.1**	$ 147.5	$ 125.1
Adjustments to reconcile net income from continuing operations to net cash provided from operating activities			
Cumulative effect of change in accounting principle	**---**	---	5.4
Depreciation	**186.1**	175.0	173.6
Impairment of assets	**---**	7.8	10.2
Deferred income taxes and investment tax credits, net	**21.9**	50.5	114.3
Allowance for equity funds used during construction	**---**	(0.9)	---
Loss (gain) on sale of assets	**0.1**	(6.5)	(0.4)
Price risk management assets	**(62.6)**	(20.0)	(21.5)
Price risk management liabilities	**80.1**	9.5	12.3
Other assets	**(6.7)**	(27.9)	(8.3)
Other liabilities	**(2.1)**	11.0	0.4
Change in certain current assets and liabilities			
Accounts receivable, net	**(106.9)**	(136.5)	(45.4)
Accrued unbilled revenues	**3.7**	(7.5)	(9.8)
Fuel, materials and supplies inventories	**22.1**	52.5	(54.8)
Gas imbalance asset	**67.8**	(29.8)	(22.5)
Fuel clause under recoveries	**(46.8)**	(50.3)	10.7
Other current assets	**12.4**	10.0	(15.9)
Accounts payable	**40.1**	194.2	18.3
Customers deposits	**(0.5)**	6.7	1.0
Accrued taxes	**53.9**	(4.5)	(1.1)
Accrued interest	**(0.9)**	(0.7)	(1.7)
Fuel clause over recoveries	**---**	(32.4)	32.4
Gas imbalance liability	**19.7**	(6.5)	0.6
Other current liabilities	**(1.2)**	11.9	19.4
Net Cash Provided from Operating Activities	**446.3**	353.1	342.3
CASH FLOWS FROM INVESTING ACTIVITIES			
Capital expenditures (less allowance for equity funds used during construction)	**(298.7)**	(430.9)	(180.8)
Proceeds from sale of assets	**5.8**	9.2	6.4
Other investing activities	**0.1**	0.7	1.6
Net Cash Used in Investing Activities	**(292.8)**	(421.0)	(172.8)
CASH FLOWS FROM FINANCING ACTIVITIES			
Retirement of long-term debt	**(254.3)**	(206.2)	(29.0)
Increase (decrease) in short-term debt, net	**125.0**	(77.5)	(72.5)
Proceeds from long-term debt	**---**	186.0	---
Premium on issuance of common stock	**14.7**	62.5	171.3
Dividends paid on common stock	**(120.0)**	(114.6)	(98.6)
Net Cash Used in Financing Activities	**(234.6)**	(149.8)	(28.8)
DISCONTINUED OPERATIONS			
Net cash (used in) provided from operating activities	**(51.4)**	38.5	(7.4)
Net cash provided from (used in) investing activities	**147.9**	(0.8)	47.9
Net cash (used in) provided from financing activities	**(0.1)**	(21.4)	1.8

Net Cash Provided from Discontinued Operations	**96.4**	16.3	42.3
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	**15.3**	(201.4)	183.0
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	**11.1**	212.5	29.5
CASH AND CASH EQUIVALENTS AT END OF PERIOD	**$ 26.4**	$ 11.1	$ 212.5

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

39

OGE ENERGY CORP.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Summary of Significant Accounting Policies

Organization

OGE Energy Corp. (collectively, with its subsidiaries, 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 two business segments, the Electric Utility and the Natural Gas Pipeline segments. 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 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, is the largest electric utility in Oklahoma and its franchised service territory includes the Fort Smith, Arkansas area. OG&E sold its retail gas business in 1928 and is no longer engaged in the gas distribution business.

The operations of the Natural Gas Pipeline segment are conducted through Enogex Inc. and its subsidiaries (Enogex) and consist of three related businesses: (i) the transportation and storage of natural gas, (ii) the gathering and processing of natural gas and (iii) the marketing of natural gas. The vast majority of Enogex s natural gas gathering, processing, transportation and storage assets are located in the major gas producing basins of Oklahoma. Prior to October 31, 2005, Enogex owned, through a 75 percent interest in the NOARK Pipeline System Limited Partnership (NOARK), a controlling interest in and operated Ozark Gas Transmission, L.L.C. (OGT), a FERC regulated interstate pipeline that extends from southeast Oklahoma through Arkansas to southeast Missouri. On October 31, 2005, Enogex sold its interest in Enogex Arkansas Pipeline Corporation (EAPC), which held the NOARK interest. Also, during the third quarter of 2005, Enogex Compression Company, LLC (Enogex Compression) sold it majority interest in Enerven Compression Services, LLC (Enerven), a joint venture focused on the rental of natural gas compression assets. The EAPC and Enerven businesses have been reported as discontinued operations in the Company s Consolidated Financial Statements (see Note 4 for a further discussion).

The Company allocates operating costs to its affiliates based on several factors. Operating costs directly related to specific affiliates are assigned to those affiliates. Where more than one affiliate benefits from certain expenditures, the costs are shared between those affiliates receiving the benefits. Operating costs incurred for the benefit of all affiliates are allocated among the affiliates, based primarily upon head-count, occupancy, usage or 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. The Company adopted the Distrigas method in January 1996 as a result of a recommendation by the OCC Staff. The Company believes this method provides a reasonable basis for allocating common expenses.

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 the accounting principles prescribed by the Financial Accounting Standards Board (FASB) Statement of Financial Accounting Standards (SFAS) No. 71, Accounting for the Effects of Certain Types of Regulation. SFAS No. 71 provides 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 December 31:

(In millions)	**2005**	2004
Regulatory Assets		
Fuel clause under recoveries	**$ 101.1**	$ 54.3
Income taxes recoverable from customers, net	**32.8**	30.9
McClain Plant deferred expenses	**24.9**	11.0
Unamortized loss on reacquired debt	**21.3**	21.0
Recoverable take or pay gas charges	**4.9**	17.0

Cogeneration credit rider under recovery	**3.7**		---	
January 2002 ice storm	**---**		1.8	
Arkansas transition costs	**---**		0.7	
Miscellaneous	**0.5**		0.6	
Total Regulatory Assets	**$**	**189.2**	$	137.3
Regulatory Liabilities				
Accrued removal obligations, net	**$**	**114.3**	$	122.2
Deferred gain on sale of assets	**3.8**		---	
Total Regulatory Liabilities	**$**	**118.1**	$	122.2

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 cost in periods of rising prices above the baseline charge for fuel and over recovers fuel cost when prices decline below the baseline charge for fuel. Provisions in the fuel clauses allow OG&E to amortize under or over recovery. In September 2005, OG&E increased its Oklahoma fuel adjustment factor from 0.0112500 per kwh to 0.0171760 per kwh in order to reduce the under recovery. In accordance with the OCC order received by OG&E in December 2005 in its rate case, beginning in January 2006, OG&E s mechanism for the recovery of over or under recovered fuel costs from its customers was modified to allow interest to be applied to the over or under recovery.

Income taxes recoverable from customers represent income tax benefits previously used to reduce OG&E s revenues. These amounts are being recovered in rates as the temporary differences that generated the income tax benefit turn around. The provisions of SFAS No. 71 allowed OG&E to treat these amounts as regulatory assets and liabilities and they are being amortized over the estimated remaining life of the assets to which they relate. The income tax related regulatory assets and liabilities are netted on the Company s Consolidated Balance Sheets in the line item, Income Taxes Recoverable from Customers, Net. At December 31, 2005, the balance of income taxes recoverable from customers, net was approximately $32.8 million. The OCC authorized approximately $30.1 million of the $32.8 million regulatory asset to be included in OG&E s rate base for purposes of earning a return.

As a result of the acquisition of a 77 percent interest in the 520 megawatt (MW) natural gas-fired combined cycle NRG McClain Station (the McClain Plant) completed on July 9, 2004, and consistent with the 2002 agreed-upon settlement of an OG&E rate case (the Settlement Agreement) with the OCC, OG&E had the right to accrue a regulatory asset, for a period not to exceed 12 months subsequent to the acquisition and operation of the McClain Plant, consisting of the non-fuel operation and maintenance expenses, depreciation, cost of debt associated with the investment and ad valorem taxes. OG&E s rate case application included an estimate of $25.9 million related to the McClain Plant regulatory asset. At December 31, 2005, the actual incurred expenses included in the McClain Plant regulatory asset were approximately $24.9 million. Such costs will be recovered over a four-year time period as authorized in the OCC rate order beginning in January 2006. The OCC also authorized approximately $15.5 million of the $24.9 million regulatory asset to be included in OG&E s rate base for purposes of earning a return. See Note 15 for further information regarding this rate case.

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.

Recoverable take or pay gas charges represent OG&E s estimate of the amount that it could be obligated to pay under certain take-or-pay contracts. OG&E believes that it is entitled to recover any such amounts from its customers through its regulatorily approved automatic fuel adjustment clauses or other regulatory mechanisms. The recoverable take or pay gas charges are not included in OG&E s rate base and do not otherwise earn a rate of return.

In January 2005, a cogeneration credit rider was implemented at OG&E as part of the Oklahoma retail customer electric rates in order to return purchase power capacity payment reductions and any change in operating and maintenance expense related to cogeneration previously included in base rates to OG&E s customers. The balance of the cogeneration credit rider under recovery was approximately $3.7 million at December 31, 2005. Any 2005 over/under recovery of the cogeneration credit rider is automatically included in the 2006 rider. In December 2005, the OCC order in OG&E s recently completed rate case authorized a new cogeneration credit rider effective January 2006. The 2006 cogeneration credit rider is approximately $78.7 million and the 2005 under recovery was approximately $3.7 million. The cogeneration credit rider under recovery is not included in OG&E s rate base and does not otherwise earn a rate of return. The cogeneration credit rider under recovery is included in Prepayments and Other on the Company s Consolidated Balance Sheets.

Accrued removal obligations represent asset retirement costs previously recovered from ratepayers for other than legal obligations. In accordance with SFAS No. 143, Accounting for Asset Retirement Obligations, OG&E was required to reclassify its accrued removal obligations, which had previously been recorded as a liability in Accumulated Depreciation, to a regulatory liability.

During 2004, OG&E sold assets including its interest in certain natural gas producing properties and the sale of land near the Company s principal executive offices for a gain of approximately $3.5 million. During 2005, OG&E sold certain assets for a gain of approximately $0.3 million. In December 2005, the OCC order in OG&E s recently completed rate case required that any previously recognized gain in 2004 related to the sale of assets should be returned to customers through electric rates at a rate of approximately $1.3 million annually. During 2005, OG&E reversed these gains and reclassified them to Other Deferred Credits and Other Liabilities as a regulatory liability. OG&E recorded gains from the sale of assets in 2005 in a similar manner and expects to continue that treatment for future gains from the sale of assets.

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 reduced or written off, as appropriate. If the Company were required to discontinue the application of SFAS No. 71 for some or all of its operations, it could result in writing off the related regulatory assets; the financial effects of which could be significant.

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 affect on the Company s Consolidated Financial Statements particularly as they relate to pension expense and impairment estimates. 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 is in the valuation of pension plan assumptions, impairment estimates, contingency reserves, accrued removal obligations, regulatory assets and liabilities, unbilled revenue for OG&E, operating revenues for Enogex, natural gas purchases for Enogex, the allowance for uncollectible accounts receivable, the valuation of energy purchase and sale contracts and fair value and cash flow hedging policies.

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.

The Company s cash management program utilizes controlled disbursement banking arrangements. Outstanding checks in excess of cash balances were approximately $55.0 million and $33.9 million at December 31, 2005 and 2004, respectively, and are classified as Accounts Payable in the Consolidated Balance Sheets. Sufficient funds were available to fund these outstanding checks when they were presented for payment.

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. 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 the Company believes the required payment of specific amounts owed is unlikely to occur. The allowance for uncollectible accounts receivable was approximately $3.7 million and $4.5 million at December 31, 2005 and 2004, 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 which is refunded when the account is closed. New residential customers, whose outside credit scores indicate risk, are required to provide a security deposit which is refunded after 12 months of good payment history per the regulatory rules. The payment behavior of all existing customers is monitored and if the payment behavior indicates sufficient risk per the regulatory rules, 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 condition (including credit rating), collateral requirements under certain circumstances and the use of standardized agreements which provide for the netting of cash flows associated with a single counterparty. Enogex also monitors the financial condition 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. These inventories are accounted for under the last-in, first-out (LIFO) cost method. The estimated replacement cost of fuel inventories was higher than the stated LIFO cost by approximately $19.1 million and $13.7 million for 2005 and 2004, respectively, based on the average cost of fuel purchased. The amount of fuel inventory was approximately $27.9 million and $42.2 million at December 31, 2005 and 2004, respectively.

Enogex

Natural gas inventory used in Enogex s business is recorded at the lower of cost or market. In order to minimize risk, OGE Energy Resources, Inc. (OERI) enters into contracts or hedging instruments to hedge the fair value of this inventory. The fair value of the hedging instruments is recorded on the books of OERI as a Price Risk Management asset or liability with an offsetting gain or loss recorded in current earnings. OERI has elected not to designate inventory hedging contracts as fair value or cash flow hedges under SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities, as amended. As part of its recurring business activity, OERI injects and withdraws natural gas under the terms of storage capacity contracts. The amount of Enogex s natural gas inventory was approximately $35.7 million and $46.8 million at December 31, 2005 and 2004, respectively.

Gas Imbalances

Gas imbalances occur when the actual amounts of natural gas delivered from or received by Enogex s pipeline system differ from the amounts scheduled to be delivered or received. Imbalances are due to or due from shippers and operators and can be settled in cash or made up in-kind. Enogex values all imbalances at an average of current market indices applicable to Enogex s operations, not to exceed net realizable value. Also, included in Gas Imbalances on the Consolidated Balance Sheets are planned or managed imbalances related to OERI s business, referred to as park and loan transactions. Park and loan assets were approximately $15.7 million and $76.0 million, respectively, at December 31, 2005 and 2004 and park and loan liabilities were approximately $10.2 million and $2.4 million, respectively, at December 31, 2005 and 2004. Operational imbalance assets were approximately $16.3 million and $23.8 million, respectively, at December 31, 2005 and 2004 and operational imbalance liabilities were approximately $25.6 million and $13.9 million, respectively, at December 31, 2005 and 2004.

Property, Plant and Equipment

OG&E

All property, plant and equipment are recorded at cost. Newly constructed plant is added to plant balances at costs which include contracted services, direct labor, materials, overheads, transportation costs and the allowance for funds used during construction (AFUDC). Replacements of units of property are capitalized as plant. For group assets, the replaced plant is removed from plant balances and the cost of such property less net salvage is charged to Accumulated Depreciation. For non-group assets, the replaced plant is removed from plant balances with the related accumulated depreciation and the remaining balance 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.

OG&E owns a 77 percent in the McClain Plant and, as disclosed below, only OG&E s 77 percent interest is reflected in the balances in the table below. The owner of the remaining 23 percent interest in the McClain Plant is the Oklahoma Municipal Power Authority (OMPA). OG&E and OMPA are responsible for providing their own financing of capital expenditures. Also, only OG&E s proportionate interest of any direct expenses of the McClain Plant such as fuel, maintenance expense and other operating expenses is included in the applicable financial statements captions in the Consolidated Statements of Income. The balance of OG&E s interest in the McClain Plant asset is approximately $174.0 million and $173.8 million, respectively, at December 31, 2005 and 2004. The accumulated depreciation associated with OG&E s interest in the McClain Plant is approximately $14.3 million and $4.2 million, respectively, at December 31, 2005 and 2004.

Enogex

All property, plant and equipment are recorded at cost. Newly constructed plant is added to plant balances at costs which include contracted services, direct labor, materials, overheads and transportation costs used during construction. Replacements of units of property are capitalized as plant. For group assets, the replaced plant is removed from plant balances and charged to Accumulated Depreciation. For non-group assets, the replaced plant is removed from plant balances with the related accumulated depreciation and the remaining balance 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.

The Company s property, plant and equipment are divided into the following major classes at December 31, 2005 and 2004, respectively.

December 31 *(In millions)*	**2005**	2004
OGE Energy Corp. (holding company)		
Property, plant and equipment	**$ 76.3**	$ 65.2
OGE Energy Corp. property, plant and equipment	**76.3**	65.2
OG&E		
Distribution assets	**2,048.0**	1,934.0
Electric generation assets	**1,870.9**	1,828.3
Transmission assets	**597.0**	552.8
Intangible plant	**8.6**	6.3
Other property and equipment	**303.4**	313.0
OG&E property, plant and equipment	**4,827.9**	4,634.4
Enogex		
Transportation and storage assets	**683.6**	736.6
Gathering and processing assets	**566.5**	478.8

Marketing assets	**7.5**	7.5
Enogex property, plant and equipment	**1,257.6**	1,222.9
Total property, plant and equipment	**$ 6,161.8**	$ 5,922.5

44

Depreciation

OG&E

The provision for depreciation, which was approximately 3.0 percent and 2.9 percent, respectively, of the average depreciable utility plant for 2005 and 2004, 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. During early 2005, a depreciation study for OG&E was performed and new proposed depreciation rates were included as part of OG&E s May 20, 2005 rate case application with the OCC. In the OCC rate order issued in December 2005, the OCC approved the proposed depreciation rates which were implemented effective January 1, 2006. In 2006, the provision for depreciation is projected to be approximately 2.8 percent of the average depreciable utility plant. Amortization of intangibles other than debt costs is computed using the straight-line method. Approximately 75 percent of the intangible plant balance at December 31, 2005 will be amortized over three years with the remaining intangible plant being amortized over their respective lives ranging up to 25 years.

Enogex

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

Impairment of Assets

The Company assesses potential impairments of assets or asset groups when there is evidence that events or changes in circumstances require an analysis of the recoverability of an asset or asset group. For purposes of recognition and measurement of an impairment loss, a long-lived asset or assets shall be grouped with other assets and liabilities at the lowest level for which identifiable cash flows are largely independent of the cash flows of other assets and liabilities. Estimates of future cash flows used to test the recoverability of a long-lived asset or asset group 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 or asset group. The fair value of these assets is based on third-party evaluations, prices for similar assets, historical data and projected cash flow. 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. Enogex expects to continue to evaluate the strategic fit and financial performance of each of its assets in an effort to ensure a proper economic allocation of resources. The magnitude and timing of any potential impairment or gain on the disposition of any assets is not known at this time.

Allowance for Funds Used During Construction

AFUDC is calculated according to the FERC pronouncements for the imputed cost of equity and borrowed funds. AFUDC, a non-cash item, is reflected as a credit in the Consolidated Statements of Income and as a charge to Construction Work in Progress in the Consolidated Balance Sheets. AFUDC rates, compounded semi-annually, were 3.78 percent, 4.99 percent and 1.67 percent for the years 2005, 2004 and 2003, respectively. The decrease in the AFUDC rates in 2005 was primarily due to a higher level of short-term borrowings in 2005.

Revenue Recognition

OG&E

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. An amount is accrued as a receivable for this unbilled revenue 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.

Enogex

Operating revenues for transportation, storage, gathering and processing services for Enogex are recorded each month based on the current month s estimated volumes, current commodity prices, historical seasonal fluctuations and any

45

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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 natural gas liquids 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.

Estimates for gas purchases are based on sales 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.

The Company recognizes revenue from natural gas gathering, processing, transportation and storage services to third parties as services are provided. Revenue associated with natural gas liquids is recognized when the production is sold. Substantially all of OERI s natural gas contracts qualify as derivatives and, therefore, are accounted for at fair value as prescribed in SFAS No. 133. Under fair value accounting, fixed-price forwards, swaps, options, futures and other financial instruments with third parties are recorded at estimated fair market values, net of reserves, with the corresponding market changes in fair value recognized in earnings and offsetting amounts recorded as Price Risk Management assets, liabilities or against the brokerage deposits in Prepayments and Other in the Consolidated Balance Sheets.

Automatic Fuel Adjustment Clauses

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

Stock-Based Compensation

Pursuant to the provisions of SFAS No. 123, Accounting for Stock-Based Compensation, the Company has elected to continue using the intrinsic value method of accounting for its stock-based employee compensation plans in accordance with Accounting Principles Board (APB) Opinion No. 25, Accounting for Stock Issued to Employees. Accordingly, the Company has not recognized compensation expense for its stock-based awards to employees. See Note 8 for a further discussion related to the Company s Stock Incentive Plan. The Company will adopt SFAS No. 123 (Revised), Share-Based Payment, effective January 1, 2006, which will require the Company to measure and recognize the cost of employee services received in exchange for an award of equity instruments based on the grant-date fair value of the award. The following table reflects pro forma net income and income per average common share had the Company elected to adopt the fair value based method of SFAS No. 123:

Year Ended December 31 *(In millions, except per share data)*	**2005**	2004	2003
Net income, as reported	**$ 211.0**	$ 153.5	$ 129.8
Add: Stock-based employee compensation expense included in reported net income, net of related tax effects	**---**	---	---
Deduct: Stock-based employee compensation expense determined under fair value based method for all awards, net of related tax effects	**0.5**	1.0	1.2
Pro forma net income	**$ 210.5**	$ 152.5	$ 128.6

Income per average common share			
Basic as reported	**$ 2.34**	$ 1.74	$ 1.59
Basic pro forma	**$ 2.33**	$ 1.73	$ 1.57
Diluted as reported	**$ 2.32**	$ 1.73	$ 1.58
Diluted pro forma	**$ 2.32**	$ 1.72	$ 1.57

46

Accrued Vacation

The Company accrues vacation pay by establishing a liability for vacation earned during the current year, but not payable until the following year.

Accumulated Other Comprehensive Loss

The components of accumulated other comprehensive loss at December 31, 2005 and 2004 are as follows:

December 31 *(In millions)*	**2005**	2004
Minimum pension liability adjustment, net of tax	**$ (91.1)**	$ (72.7)
Deferred hedging gains, net of tax	**3.1**	0.2
Settlement and amortization of cash flow hedge, net of tax	**(2.2)**	(2.5)
Total accumulated other comprehensive loss, net of tax	**$ (90.2)**	$ (75.0)

Minimum Pension Liability Adjustment

Accumulated other comprehensive loss included approximately a $91.1 million after tax loss ($148.6 million pre-tax) and approximately a $72.7 million after tax loss ($118.6 million pre-tax), respectively, at December 31, 2005 and 2004 related to a minimum pension liability adjustment based on a review of the funded status of the Company s pension plan by the Company s actuarial consultants as of December 31, 2005.

Cash Flow Hedges of Interest Rates

OG&E entered into two separate treasury lock agreements, effective November 14, 2005 and November 16, 2005, respectively, to hedge approximately $50.0 million each of future interest payments of long-term debt that was issued in January 2006. These treasury locks were terminated in early December due to the lack of an OCC order in OG&E s rate case at the time. OG&E entered into two separate treasury lock agreements, effective December 28, 2005, to hedge approximately $50.0 million each of future interest payments of long-term debt that was issued in January 2006. These treasury locks were terminated on January 6, 2006 after OG&E issued long-term debt. OG&E received less than $0.1 million related to the termination of the aforementioned treasury lock agreements.

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 has been designated as one of several potentially responsible parties, the amount accrued represents OG&E s estimated share of the cost.

Reclassifications

Certain prior year amounts have been reclassified on the Consolidated Financial Statements to conform to the 2005 presentation.

2. Accounting Pronouncements

In October 2002, the Emerging Issues Task Force (EITF) reached a consensus on certain issues covered in EITF Issue No. 02-3, Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities. One consensus of EITF 02-3 was to rescind EITF Issue No. 98-10, Accounting for Contracts Involved in Energy Trading and Risk Management Activities, as amended, effective for fiscal periods beginning after December 15, 2002. Effective October 25, 2002, all new contracts and physical inventories that would have been accounted for under EITF 98-10 were no longer marked to market through earnings unless the contracts met the definition of a derivative under SFAS No. 133. Application of the consensus for energy contracts and inventory that existed on or before October 25, 2002 that remain in effect at the date this consensus was initially applied were recognized as a cumulative effect of a change in accounting principle in accordance with APB Opinion No. 20, Accounting Changes. As a result, only energy contracts that meet the definition of a derivative in SFAS No. 133 are carried at fair value. The Company adopted this consensus effective January 1, 2003 resulting in a pre-tax loss of approximately $9.6 million ($5.9 million after tax). The loss, which was accounted for as a cumulative effect of a change in accounting principle during the first quarter of 2003, was primarily related to natural gas held in storage for trading purposes. This natural gas held in storage was sold during the first quarter of 2003 resulting in an increase in the gross margin on revenues (gross margin) in excess of the cumulative effect loss described above.

In November 2004, the FASB issued SFAS No. 151, Inventory Costs, an Amendment to ARB No. 43, Chapter 4. This statement amends the guidance in Accounting Research Bulletin No. 43, Chapter 4 Inventory Pricing , to clarify the accounting for abnormal amounts of idle facility expense, freight, handling costs and spoilage. This statement requires these items to be recognized as current period charges regardless of whether the so abnormal criterion is met. Adoption of SFAS No. 151 is required for inventory costs incurred during fiscal years beginning after June 15, 2005. The Company will adopt this new standard effective January 1, 2006. Management does not expect the impact of this new standard to have a material effect on its consolidated financial position or results of operations.

In December 2004, the FASB issued SFAS No. 123 (Revised), which replaces SFAS No. 123 and supersedes APB Opinion No. 25. This statement applies to all share-based payment transactions in which an entity acquires goods or services by issuing (or offering to issue) its shares, share options or other equity instruments (except for equity instruments held by an employee share ownership plan) or by incurring liabilities to an employee or other supplier (a) in amounts based, at least in part, on the price of the entity s shares or other equity instruments or (b) that require or may require settlement by issuing the entity s equity shares or other equity instruments. This statement applies to all awards granted after the required effective date and to awards modified, repurchased or cancelled after that date. The cumulative effect of initially applying this statement, if any, is recognized as of the required effective date. This statement requires a public entity to measure and recognize the cost of employee services received in exchange for an award of equity instruments based on the grant-date fair value of the award (with limited exceptions). The grant-date fair value of employee share options and similar instruments will be estimated using option-pricing models adjusted for the unique characteristics of those instruments. If an equity award is modified after the grant date, incremental compensation cost will be recognized in an amount equal to the excess of the fair value of the modified award over the fair value of the original award immediately before the modification. As of the required effective date, all public entities that used the fair-value based method for either recognition or disclosure under SFAS No. 123 will apply this statement using a modified version of prospective application. Under that transition method, compensation cost is recognized on or after the required effective date for the portion of outstanding awards for which the requisite service has not yet been rendered, based on the grant-date fair value of those awards calculated under SFAS No. 123 for either recognition or pro forma disclosures. Adoption of SFAS No. 123(R) is required for public entities as of the beginning of the first annual period beginning after June 15, 2005. The Company will adopt this new standard effective January 1, 2006. Management does not expect the impact of this new standard to have a material effect on its consolidated financial position or results of operations.

In March 2005, the FASB issued FASB Interpretation No. 47, Accounting for Conditional Asset Retirement Obligations, in which an entity is required to recognize a liability for the fair value of an asset retirement obligation (ARO) that is conditional on a future event if the liability s fair value can be reasonably estimated. The fair value of a liability for the conditional ARO should be recognized when incurred. Uncertainty surrounding the timing and method of settlement of a conditional ARO should be factored into the measurement of the liability when sufficient information exists. However, in some cases, there is insufficient information to estimate the fair value of an ARO. In these cases, the liability should be initially recognized in the period in which sufficient information is available for an entity to make a reasonable estimate of the liability s fair value. FIN 47 required both recognition of a cumulative change in accounting principle and disclosure of the liability on a pro forma basis for transition purposes. FIN 47 is effective no later than the end of fiscal years ending after December 15, 2005. The Company adopted this new interpretation effective December 31, 2005 which resulted in an ARO of approximately $2.5 million being recorded for power plant structure legal obligations associated with various removal items, of which approximately $0.4 million is the ARO and approximately $2.1 million are cumulative accretion costs. Beginning January 1, 2006, the Company will amortize the remaining value of the related ARO assets over their remaining lives ranging from 20 to 50 years. The cumulative accretion costs of approximately $2.1 million that are included in the ARO were reclassified from the regulatory liability account associated with Accrued Removal Obligations to Asset Retirement Obligations on the Consolidated Balance Sheet and, as a result, there was no earnings impact from a cumulative effect adjustment due to a change in accounting principle. In addition, the cumulative depreciation expense for the ARO assets of approximately $0.2 that would have been recorded for the time period from the date the liability would have been originally recorded under FIN 47 was also reclassified from the regulatory liability account to accumulated depreciation for the ARO assets with no earnings impact. At December 31, 2003 and 2004, the pro forma amount of the ARO would have been approximately $2.4 million. The Company has identified other ARO s that have not been recorded because the Company determined that these assets have indefinite lives primarily related to OG&E s power plant sites and Enogex s processing plants.

In June 2005, the FASB issued SFAS No. 154, Accounting Changes and Error Corrections, which replaces APB Opinion No. 20, Accounting Changes and SFAS No. 3, Reporting Accounting Changes in Interim Financial Statements. SFAS No. 154 applies to all voluntary changes in accounting principle and requires retrospective application to prior periods financial statements of changes in accounting principle unless it is impracticable to determine either the period-specific effects or the cumulative effect of the change. Adoption of SFAS No. 154 is required for accounting changes and error corrections made in fiscal years beginning after December 15, 2005. The Company will adopt this new standard effective January 1, 2006. Management does not expect the impact of this new standard to have a material effect on its consolidated financial position or results of operations.

In September 2005, the EITF reached a consensus and issued EITF Issue No. 04-13, Accounting for Purchases and Sales of Inventory with the Same Counterparty in which inventory purchase and sale transactions with the same counterparty that are entered into in contemplation of one another should be combined for purposes of applying APB Opinion No. 29, Accounting for Nonmonetary Transactions. The EITF also concluded that exchanges of inventory should be recognized at carryover basis except for changes of finished goods for either raw materials or work in progress, which would be recognized at fair value. This consensus should be applied in the first interim or annual reporting period beginning after March 15, 2006 to new arrangements and previous arrangements that were modified or renegotiated after the effective date. Management does not expect the impact of this new standard to have a material effect on its consolidated financial position or results of operations.

3. Price Risk Management Assets and Liabilities

Non-Trading Activities

The Company periodically utilizes derivative contracts to manage the exposure of its assets to unfavorable changes in commodity prices, as well as to reduce exposure to adverse interest rate fluctuations. During 2005 and 2004, the Company s use of non-trading price risk management instruments involved the use of commodity price futures, commodity price swap contracts, interest rate swap agreements and treasury lock agreements. The commodity price futures, commodity price swap contracts and interest rate swap agreements involved the exchange of fixed price or rate payments in exchange for floating price or rate payments over the life of the instrument without an exchange of the underlying principal amount. The treasury lock agreements protected against the variability of future interest payments of long-term debt that was issued by OG&E in January 2006.

In accordance with SFAS No. 133, the Company recognizes its non-exchange traded derivative instruments as Price Risk Management 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 that are subject to a master netting agreement 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 Prepayments and Other in the Consolidated Balance Sheets. The accounting for changes in the fair value of a derivative depends on the intended use of the derivative and resulting designation. For derivative instruments that are designated and qualify as a fair value hedge, the gain or loss on the derivative instrument is recognized in current earnings on the same line item as the gain or loss recorded for the change in the fair value of the hedged item. For derivatives that are designated and qualify as a cash flow hedge, the effective portion of the change in fair value of the derivative instrument is reported as a component of Accumulated Other Comprehensive Income and recognized into earnings in the same period during which the hedged transaction affects earnings. The ineffective portion of a derivative s change in fair value is recognized currently in earnings. Forecasted transactions designated as the hedged item 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. If the forecasted transactions are no longer reasonably possible of occurring, any associated amounts recorded in Accumulated Other Comprehensive Income will also be recognized directly in earnings.

The Company may designate certain derivative instruments for the purchase or sale of physical commodities, purchase or sale of electric power and fuel procurement as normal purchases and normal sales contracts under the provisions of SFAS No. 133. Normal purchases and normal sales contracts are not recorded in Price Risk Management assets or liabilities in the Consolidated Balance Sheets and earnings recognition is recorded in the period in which physical delivery of the commodity occurs. The Company applies normal purchases and normal sales to commodity contracts for the sale of

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natural gas liquids produced by its subsidiary, Enogex Products Corporation (Products), to electric power contracts by OG&E and for fuel procurement by OG&E.

At December 31, 2005, the Company had no outstanding interest rate swap agreements. At December 31, 2005, the Company s treasury lock agreements have been designated as cash flow hedges under SFAS No. 133. The Company measures ineffectiveness of the cash flow hedges under the hypothetical derivative method prescribed by SFAS No. 133. Under the hypothetical derivative method, the Company has designated that the critical terms of the hedging instrument are the same as the critical terms of the hypothetical derivative used to value the forecasted transaction, and, as a result, no ineffectiveness is expected. See Note 1 for a description of the Company s treasury lock agreements.

Trading Activities

The Company, through its subsidiary, OERI, engages in energy trading activities primarily related to the purchase and sale of natural gas. Contracts utilized in these activities generally include forward swap contracts as well as over-the-counter and exchange traded futures and options. Energy trading activities are accounted for in accordance with SFAS No. 133 and EITF Issue No. 02-3. In accordance with SFAS No. 133, financial instruments that qualify as derivatives are reflected at fair value with the resulting unrealized gains and losses recorded as Price Risk Management assets or liabilities in the Consolidated Balance Sheets, classified as current or long-term based on their anticipated settlement. Unrealized gains and losses from changes in the market value of open contracts are included in Natural Gas Pipeline Operating Revenues in the Consolidated Statements of Income. Energy trading contracts resulting in delivery of a commodity that meet the requirements of EITF Issue No. 99-19, Reporting Revenues Gross as a Principal or Net as an Agent, are included as sales or purchases in the Consolidated Statements of Income depending on whether the contract relates to the sale or purchase of the commodity.

4. Enogex Discontinued Operations

In April 2005, Enogex Compression received an unsolicited offer to buy its interest in Enerven, a joint venture focused on the rental of natural gas compression assets. After evaluating this offer, Enogex Compression sold its interest in Enerven for approximately $7.3 million in August 2005. Enogex Compression recognized an after tax gain of approximately $1.8 million related to the sale of this business.

Enogex regularly evaluates long term stability, profitability and core competency of each of its businesses within the regulatory and market framework in which each business operates. Based on these evaluations, in September 2005, Enogex announced that it had entered into an agreement to sell its interest in EAPC, which held the NOARK interest. This sale was completed on October 31, 2005. The Company received approximately $177.4 million cash proceeds and recognized an after tax gain of approximately $36.7 million from the sale of this business in the fourth quarter. Enogex used approximately $31.9 million of the proceeds to repay principal and accrued interest on long-term debt and approximately $46.7 million to pay taxes associated with EAPC. The balance of the proceeds of approximately $98.8 million will be used to invest, over time, in strategic assets to diversify its asset base.

The Consolidated Financial Statements of the Company have been restated to reflect Enogex Compression s sale of its Enerven interest and Enogex s sale of its EAPC interest, both of which were part of the Natural Gas Pipeline segment, as discontinued operations. Accordingly, revenues, costs and expenses and cash flows of Enerven and EAPC have been excluded from the respective captions in the Consolidated Financial Statements and have been separately reported as discontinued operations in the applicable financial statement captions. Summarized financial information for the discontinued operations as of December 31 is as follows:

CONSOLIDATED STATEMENTS OF INCOME DATA

(In millions)	**2005**	2004	2003
Operating revenues from discontinued operations	**$ 69.3**	$ 78.3	$ 79.8
Income from discontinued operations before taxes	**76.2**	9.4	9.8

CONSOLIDATED BALANCE SHEET DATA

(In millions)	**2005**	2004
Cash and cash equivalents	**$ ---**	$ 3.3

Accounts receivable, net	**---**	3.4
Other	**---**	0.5
Total current assets of discontinued operations	**$ ---**	$ 7.2
Plant in service of discontinued operations	**$ ---**	$ 151.4
Less accumulated depreciation	**---**	18.8
Net property, plant and equipment of discontinued operations	**$ ---**	$ 132.6
Total deferred charges and other assets of discontinued operations	**$ ---**	$ 4.7
Accounts payable	**$ ---**	$ 5.9
Accrued interest	**---**	0.4
Long-term debt due within one year	**---**	2.0
Other	**---**	1.3
Total current liabilities of discontinued operations	**$ ---**	$ 9.6
Total long-term debt of discontinued operations	**$ ---**	$ 65.0
Total deferred credits and other liabilities of discontinued operations	**$ ---**	$ 18.3

5. Supplemental Cash Flow Information

The following table discloses information about investing and financing activities that affect recognized assets and liabilities but which do 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.

Year ended December 31 *(In millions)*	**2005**	2004	2003
NON-CASH INVESTING AND FINANCING ACTIVITIES			
Change in fair value of long-term debt due to interest rate swaps	**$ (7.8)**	$ 0.3	$ (8.3)
Power plant long-term service agreement	**---**	6.0	---
Issuance of common stock	**---**	2.2	11.4
Change in property, plant and equipment due to transfer of inventory	**---**	---	7.1
SUPPLEMENTAL CASH FLOW INFORMATION			
Cash Paid During the Period for			
Interest (net of interest capitalized of $2.2, $1.7, $0.5)	**$ 95.9**	$ 85.2	$ 92.6
Income taxes (net of income tax refunds)	**42.0**	37.4	(33.2)

6. Income Taxes

The items comprising income tax expense are as follows:

Year ended December 31 *(In millions)*	**2005**	2004	2003
Provision (Benefit) for Current Income Taxes from Continuing Operations			
Federal	**$ 45.3**	$ 21.8	$ (36.6)
State	**5.3**	2.5	(6.3)
Total Provision (Benefit) for Current Income Taxes from Continuing Operations	**50.6**	24.3	(42.9)
Provision for Deferred Income Taxes, net from Continuing Operations			
Federal	**27.0**	51.2	103.7
State	**---**	4.4	15.8
Total Provision for Deferred Income Taxes, net from Continuing Operations	**27.0**	55.6	119.5
Deferred Federal Investment Tax Credits, net	**(5.1)**	(5.2)	(5.2)

Income Taxes Relating to Other Income and Deductions	**(0.7)**	2.4	(0.6)
Total Income Tax Expense from Continuing Operations	**$ 71.8**	$ 77.1	$ 70.8

In connection with the filing in the third quarter of 2003 of the Company s consolidated income tax returns for 2002, the Company elected to change its tax method of accounting related to the capitalization of costs for self-constructed assets to another method prescribed in the Treasury regulations. The accounting method change is for income tax purposes only. For financial accounting purposes, the only change is recognition of the impact of the cash flow generated by accelerating income tax deductions. This is reflected in the financial statements as a switch from current income taxes payable to deferred income taxes payable. This tax accounting method change resulted in a one-time catch-up deduction for costs previously capitalized under the prior method, resulting in a consolidated tax net operating loss for 2002. This tax net operating loss eliminated the Company s current federal and state income tax liability for 2002 and 2003 and all estimated payments made for 2002 have been refunded. Estimates made for 2003 were applied to 2004. As a result of this tax net operating loss, tax credits associated with Enogex s natural gas production were not realized during 2003 and resulted in approximately $1.8 million in higher income tax expense in discontinued operations. The Company received federal and state income tax refunds of approximately $50.8 million during 2003 related to this tax accounting method change. During 2005, new guidelines were issued by the Internal Revenue Service (IRS) related to the change in the method of accounting used to capitalize costs for self-construction discussed above. As part of the Company s current IRS examination process, this change in method of accounting has been identified as an issue under examination. The Company believes its change in accounting method was in accordance with IRS regulations in effect at the time and will continue to vigorously defend its position. While the outcome of this process is uncertain at this time, during 2005 OG&E recorded approximately $3.3 million for additional interest expense related to income taxes as a result of a potential adjustment. This amount is included in Interest on Short-Term Debt and Other Interest Charges in the Consolidated Statements of Income. OG&E expects to continue to accrue approximately $0.3 million monthly in 2006 for additional interest expense related to this matter.

The following schedule reconciles the statutory federal tax rate to the effective income tax rate:

Year ended December 31	**2005**	2004	2003
Statutory federal tax rate	**35.0%**	35.0%	35.0%
State income taxes, net of federal income tax benefit	**1.7**	2.0	3.1
Excess deferred taxes (A)	**(2.2)**	---	---
Tax credits, net	**(2.1)**	(2.3)	(2.6)
ESOP dividends	**(1.7)**	---	---
Medicare Part D subsidy	**(1.3)**	---	---
Other, net	**0.8**	(0.4)	(0.3)
Effective income tax rate as reported	**30.2%**	34.3%	35.2%

(A) During 2005, the Company performed a detailed analysis of all deferred tax assets and liabilities. In connection with this analysis, it was determined that an excess liability existed. The removal of this excess liability caused a permanent difference in the effective tax rate for 2005 of approximately 2.2 percent.

The Company files consolidated income tax returns. Income taxes are allocated to each affiliate based on its separate taxable income or loss. Federal investment tax credits on electric utility property have been deferred and are being amortized to income over the life of the related property.

The Company follows the provisions of SFAS No. 109, Accounting for Income Taxes, which uses an asset and liability approach to accounting for income taxes. Under SFAS No. 109, deferred tax assets or liabilities are computed based on the difference between the financial statement and income tax bases of assets and liabilities using the enacted marginal tax rate. Deferred income tax expenses or benefits are based on the changes in the asset or liability from period to period.

The deferred tax provisions, set forth above, are recognized as costs in the ratemaking process by the commissions having jurisdiction over the rates charged by OG&E. The components of Accumulated Deferred Taxes at December 31, 2005 and 2004, respectively, are as follows:

(In millions)	**2005**	2004
Current Accumulated Deferred Tax Assets		
Accrued vacation	**$ 6.3**	$ 6.0
Provision for rate refund	**2.7**	0.4
Capitalized indirect construction costs	**1.7**	0.8
Uncollectible accounts	**1.4**	1.8
Other	**2.2**	4.7
Total Current Accumulated Deferred Tax Assets	**$ 14.3**	$ 13.7
Non-Current Accumulated Deferred Tax Liabilities		
Accelerated depreciation and other property related differences	**$ 826.4**	$ 781.6
Income taxes refundable to customers, net	**12.7**	11.9
Bond redemption-unamortized costs	**6.9**	7.3
Company pension plan	**---**	2.6
Other	**0.7**	1.3
Total Non-Current Accumulated Deferred Tax Liabilities	**846.7**	804.7
Non-Current Accumulated Deferred Tax Assets		
Postretirement medical and life insurance benefits	**(15.3)**	(10.2)
Company pension plan	**(13.6)**	---
Deferred federal investment tax credits	**(8.6)**	(10.3)
Other	**(2.1)**	---
Total Non-Current Accumulated Deferred Tax Assets	**(39.6)**	(20.5)
Non-Current Accumulated Deferred Income Tax Liabilities, net	**$ 807.1**	$ 784.2

OG&E has an Oklahoma investment tax credit carryover of approximately $6.8 million. These Oklahoma credit carryover amounts will begin expiring in the year 2017. During 2005, additional Oklahoma tax credits of approximately $4.1 million were generated by OG&E and Enogex. The Company believes that, based on current projections, the entire $10.9 million of these state tax credit amounts will be fully utilized in 2006.

In June 2005, the Company filed amended Oklahoma and Arkansas state income tax returns for the years 1993 through 2003. The returns were filed to reflect changes resulting from IRS audit adjustments as well as additional Oklahoma investment tax credits for assets placed into service prior to 2001. During the third quarter of 2005, the Company received approximately $1.6 million of the $3.8 million of state income tax and Oklahoma investment tax credit refunds for which it had applied. The Company expects to benefit from the remaining $2.2 million but is unable to predict the timing of the benefit.

American Jobs Creation Act of 2004

On October 22, 2004, President Bush signed into law the American Jobs Creation Act of 2004 (the Jobs Creation Act). The Jobs Creation Act amended and added a significant number of provisions to the Internal Revenue Code (the Code) and these changes affect virtually all taxpayers. The Jobs Creation Act includes a provision that entitles all U.S. manufacturers with qualified manufacturing activities to a Deduction Related to Production Activities (DRPA). Certain activities of the Company, including the generation of electricity and the processing of natural gas, are included in the list of qualifying manufacturing activities for purposes of the DRPA. Thus, the Company believes that the DRPA could impact the Company s future effective income tax rate.

Beginning in 2005, the DRPA equals three percent of the lesser of: (a) taxable income derived from a qualified production activity; or (b) overall taxable income for the taxable year. However, the deduction for a taxable year is limited to 50 percent of the Form W-2 wages paid by a taxpayer during the taxable year in which the deduction is claimed. The deduction percentage increases to six percent in 2007. In 2010, when the deduction is fully phased-in, the deduction rate will be nine percent.

Because OG&E is an integrated electric utility and Enogex is an integrated natural gas transportation company, both will be required to allocate income and expenses to their qualified production activity. The U.S. Treasury Department issued guidance related to the DRPA on January 19, 2005 and October 20, 2005 and this guidance provides rules for determining taxable income when a portion of a taxpayer s income is derived from a qualified production activity. The FASB has determined that the DRPA will be classified as a special deduction for purposes of computing income tax expense which will have the effect of reducing the Company s overall effective tax rate to the extent the Company can claim

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a deduction. For 2005, the Company s income tax benefit was approximately $0.5 million for OG&E and was approximately $0.5 million for Products.

7. Common Stock

In April 2003, the Company filed a Form S-3 Registration Statement registering the sale of up to $130.0 million of unsecured debt securities or shares of the Company s common stock. On August 27, 2003 and September 5, 2003, respectively, the Company issued 4,650,000 shares and 674,074 shares of its common stock under this registration statement at a public offering price of $21.60 per share.

In July 2005, the Company filed a Form S-3 Registration Statement to register 7,000,000 shares of the Company s common stock pursuant to the Company s Automatic Dividend Reinvestment and Stock Purchase Plan (DRIP/DSPP). Under the terms of the DRIP/DSPP, the Company may accept requests for optional investments in amounts greater than $0.1 million per year and may offer a discount of up to three percent from current market prices. This program allows the Company to sell additional common stock at a smaller discount than that normally incurred in a secondary equity offering. During the year ended December 31, 2005, the Company purchased common stock on the open market to satisfy the common stock requirements of the DRIP/DSPP and therefore did not issue any new shares of common stock. During the year ended December 31, 2004, the Company issued 721,021 shares of common stock and 1,238,043 shares of common stock at a discount of 1.50 percent and 1.25 percent, respectively, pursuant to the DRIP/DSPP. During the year ended December 31, 2003, the Company issued 615,721 shares of common stock and 1,855,989 shares of common stock at a discount of 1.75 percent and 1.50 percent, respectively, pursuant to the DRIP/DSPP. Also, as part of the DRIP/DSPP, the Company issued 242,003 and 938,497 shares of common stock at no discount during the years ended December 31, 2004 and 2003, respectively.

For the years ended December 31, 2005, 2004 and 2003, respectively, there were 606,802, 392,686 and 134,098 shares of new common stock issued pursuant to the Company s Stock Incentive Plan, related to exercised stock options. At December 31, 2005, there were 15,338,204 shares of unissued common stock reserved for the various employee and Company stock plans.

Shareowners Rights Plan

In December 1990, OG&E adopted a Shareowners Rights Plan designed to protect shareowners interests in the event that OG&E was ever confronted with an unfair or inadequate acquisition proposal. In connection with the corporate restructuring, the Company adopted a substantially identical Shareowners Rights Plan in August 1995. Pursuant to the plan, the Company declared a dividend distribution of one right for each share of Company common stock. As a result of the June 1998 two-for-one stock split, each share of common stock is now entitled to one-half of a right. Each right entitles the holder to purchase from the Company one one-hundredth of a share of new preferred stock of the Company under certain circumstances. The rights may be exercised if a person or group announces its intention to acquire, or does acquire, 20 percent or more of the Company s common stock. Under certain circumstances, the holders of the rights will be entitled to purchase either shares of common stock of the Company or common stock of the acquirer at a reduced percentage of the market value. In October 2000, the Shareowners Rights Plan was amended and restated to extend the expiration date to December 11, 2010 and to change the exercise price of the rights.

The Company s Restated Certificate of Incorporation permits the issuance of a new series of preferred stock with dividends payable other than quarterly.

8. Stock Incentive Plan

On January 21, 1998, the Company adopted a Stock Incentive Plan (the 1998 Plan). In 2003, the Company adopted, and its shareowners approved, a new Stock Incentive Plan (the 2003 Plan and together with the 1998 Plan, the Plans). The 2003 Plan replaced the 1998 Plan and no further awards will be granted under the 1998 Plan. As under the 1998 Plan, under the 2003 Plan, restricted stock, stock options, stock appreciation rights and performance units may be granted to officers, directors and other key employees. The Company has authorized the issuance of up to 2,700,000 shares under the 2003 Plan.

Performance Units

During 2005, 2004 and 2003, respectively, the Company awarded 201,794, 162,591 and 128,469 performance units to certain employees of the Company. These performance units represent the value of one share of the Company s common

stock. The 2003, 2004 and 2005 performance units are contingently awarded and will be payable in cash or 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 is dependent on the Company s total shareholder return relative to the total shareholder return of a peer group of companies. Also, for the 2005 performance units, the performance units are contingently awarded based on the Company s earnings per share growth over a three-year award cycle. Each performance unit 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. During 2005, 2004 and 2003, the Company recorded approximately $0.9 million, $3.6 million and $1.5 million, respectively, related to expense for the performance units which are accounted for under the liability method.

Stock Options

During 2005, no stock options were granted under the 2003 Plan. Options granted under the Plans vest in one-third annual installments beginning one year from the date of grant and have a contractual life of 10 years. To date, no options have expired unexercised. Stock option transactions related to the Plans are summarized in the following table:

	2005		2004		2003	
	Number of Options	**Weighted Average Price**	Number of Options	Weighted Average Price	Number of Options	Weighted Average Price
Options Outstanding at beginning of year	**2,827,914**	**$22.16**	2,871,802	$21.63	2,419,360	$23.44
Granted	**---**	**---**	380,400	23.58	838,700	16.69
Exercised	**(606,802)**	**21.75**	(392,686)	19.56	(134,098)	18.82
Cancelled	**(81,736)**	**24.15**	(31,602)	23.25	(252,160)	24.10
Options Outstanding at end of year	**2,139,376**	**$22.20**	2,827,914	$22.16	2,871,802	$21.63
Options Exercisable at end of year	**1,734,978**	**$22.70**	1,809,441	$23.29	1,408,255	$24.20

The fair value of each option grant under the Plans for the years ended December 31, 2004 and 2003 are estimated on the date of grant using the Black-Scholes option pricing model with the following weighted-average assumptions used for grants in 2004 and 2003. There were no stock option grants during 2005.

	2004	2003
Expected dividend yield	6.27%	6.30%
Expected price volatility	18.58%	22.06%
Risk-free interest rate	3.77%	3.80%
Expected life of options (in years)	7	7
Weighted-average fair value of options granted	$ 2.05	$ 1.85

The following table provides additional information about stock options outstanding at December 31, 2005:

		Options Outstanding		Options Exercisable	
Range of Exercise Prices	Weighted-Average Remaining Contractual Life	Number Outstanding	Weighted-Average Exercise Price	Number Outstanding	Weighted-Average Exercise Price
$16.69 - $22.70	6.03 years	1,299,173	$ 19.82	1,091,256	$ 20.41
$23.58 - $28.75	4.42 years	840,203	$ 25.88	643,722	$ 26.58

9. Earnings Per Share

Outstanding shares for purposes of basic and diluted earnings per average common share were calculated as follows:

Year ended December 31 *(In millions)*	**2005**	2004	2003
Average Common Shares Outstanding			
Basic average common shares outstanding	90.3	88.0	81.8
Effect of dilutive securities:			
Employee stock options and unvested stock grants	0.2	0.3	0.1
Contingently issuable shares (performance units)	0.3	0.2	0.2
Diluted average common shares outstanding	90.8	88.5	82.1

For the years ended December 31, 2005, 2004 and 2003, respectively, approximately 0.2 million shares, 0.6 million shares and 1.7 million shares related to outstanding employee stock options were not included in the calculation of diluted earnings per average common share because the effect of including those shares would be anti-dilutive as the exercise price of the stock options exceeded the average common stock market price during the respective period.

10. Long-Term Debt

A summary of the Company s long-term debt is included in the Consolidated Statements of Capitalization. At December 31, 2005, the Company is in compliance with all of its debt agreements.

Refinancing of Long-Term Debt

In August 2005, OG&E filed a Form S-3 Registration Statement to register the sale of up to $400.0 million of OG&E s unsecured debt securities. On October 17, 2005, OG&E paid at maturity its $110 million of 7.125 percent senior notes and redeemed its $110 million of 7.30 percent senior notes due October 15, 2025 at the principal amount plus a $3.6 million premium. The repayments were funded temporarily through the issuance of commercial paper by the Company and OG&E and borrowings under existing credit agreements which OG&E replaced with the proceeds from the issuance of $110 million of 5.15 percent senior notes and $110 million of 5.75 percent of senior notes in January 2006.

Long-Term Debt with Optional Redemption Provisions

OG&E has three series of variable rate industrial authority bonds (the Bonds) with optional redemption provisions that allow the holders to request repayment of the Bonds at various dates prior to the maturity. The Bonds, which can be tendered at the option of the holder during the next 12 months, are as follows (dollars in millions):

SERIES	**DATE DUE**	**AMOUNT**
1.56% - 3.71%	Garfield Industrial Authority, January 1, 2025	**$ 47.0**
1.80% - 3.70%	Muskogee Industrial Authority, January 1, 2025	**32.4**
1.74% - 3.63%	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, the Company is obligated to repurchase such unremarketed Bonds. The Company has sufficient liquidity to meet these obligations.

Interest Rate Swap Agreements

Fair Value Hedges

At December 31, 2005, the Company had no outstanding interest rate swap agreements. At December 31, 2004, the Company had three outstanding interest rate swap agreements that qualified as fair value hedges: (i) OG&E entered into an interest rate swap agreement, effective March 30, 2001, to convert $110.0 million of 7.30 percent fixed rate debt due October 15, 2025, to a variable rate based on the three month London InterBank Offering Rate (LIBOR) and (ii) Enogex entered into two separate interest rate swap agreements, effective July 15, 2002 and October 24, 2002, to convert a total of $200.0 million ($100.0 million for each interest rate swap agreement) of 8.125 percent fixed rate debt due January 15, 2010, to a variable rate based on the six month LIBOR in arrears. The objective of these interest rate swaps was to achieve a lower cost of debt and to raise the percentage of total corporate long-term floating rate debt to reflect a level more in line with industry standards. These interest rate swaps qualified as fair value hedges under SFAS No. 133 and met all of the requirements for a determination that there was no ineffective portion as allowed by the shortcut method under SFAS No. 133.

On April 1, 2005, Enogex terminated two interest rate swap agreements (with a total notional amount of $200 million) and received approximately $0.2 million related to this transaction. Since inception of the Enogex interest rate swap

56

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agreements, which converted $200 million of 8.125 percent fixed rate debt due January 15, 2010 to a floating rate based upon the three and six month LIBOR, the Company has paid approximately $81.3 million in interest and has received approximately $29.9 million related to these agreements. The effective interest rate until maturity will be approximately 7.67 percent on this long-term debt.

On September 1, 2005, the counterparty to OG&E s interest rate swap agreement exercised its right to change the termination date of the interest rate swap agreement from October 15, 2025 to October 15, 2005 in conjunction with the early redemption of long-term debt discussed above. On October 17, 2005, OG&E received approximately $5.3 million related to the termination of its interest rate agreement of which approximately $1.7 million is related to interest received and approximately $3.6 million is related to canceling the interest rate swap agreement, which will be amortized over the life of the long-term debt OG&E issued in January 2006.

At December 31, 2004, the fair values pursuant to the interest rate swaps were approximately $7.9 million and the hedges were classified as Deferred Charges and Other Assets Price Risk Management in the Consolidated Balance Sheet. A corresponding net increase of approximately $7.9 million was reflected in Long-Term Debt at December 31, 2004 as these fair value hedges were effective at December 31, 2004.

Long-term Debt Maturities

Maturities of the Company s long-term debt during the next five years consist of $3.0 million in 2007; $1.0 million in 2008 and $400.0 million in 2010. There are no maturities of the Company s long-term debt in years 2006 or 2009.

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

11. Short-Term Debt

The Company borrows on a short-term basis, as necessary, by the issuance of commercial paper and by loans under short-term bank facilities. The short-term debt balance was approximately $250.0 million and $125.0 million at December 31, 2005 and 2004, respectively, at a weighted-average interest rate of 4.421 percent and 2.467 percent, respectively. In accordance with SFAS No. 6, Classification of Short-Term Obligations Expected to Be Refinanced, an Amendment of ARB No. 43, Chapter 3A, $220 million in commercial paper and bank borrowings was used to temporarily fund the matured and called long-term debt for OG&E. This commercial paper was classified as long-term debt in the Consolidated Statement of Capitalization at December 31, 2005 as OG&E planned to refinance this amount. Subsequently, OG&E issued long-term debt in January 2006. The following table shows the Company s lines of credit in place, commercial paper outstanding and available cash at December 31, 2005. At December 31, 2005, the Company s short-term borrowings consisted of commercial paper.

Lines of Credit, Commercial Paper and Available Cash *(In millions)*

Entity	Amount Available	Amount Outstanding	Weighted-Average Interest Rate	Maturity
Energy Corp. (B)	$ 600.0	$ 150.0	4.435%	September 30, 2010 (A)
The Company (C)	150.0	100.0	4.400%	September 30, 2010 (A)
Energy Corp.	15.0	---	N/A	April 6, 2006
	765.0	250.0	4.421%	
Cash	26.4	N/A	N/A	N/A
Total	$ 765.0	$ 250.0	4.421%	

(A) On September 30, 2005, the Company and OG&E entered into revolving credit agreements totaling $750 million. This credit facility agreement includes two separate facilities, one for the Company in an amount up to $600 million and one for OG&E in an amount up to $150 million. Each of the credit facilities has a five-year term with two options to extend the term for one year.

(B) This bank facility is available to back up a maximum of $300.0 million of the Company s commercial paper borrowings and to provide an additional $300.0 million in revolving credit borrowings. This bank facility can also be used as a letter of credit facility. At December 31, 2005, the Company had approximately $150.0 million in commercial paper borrowings.

(C) This bank facility is available to back up a maximum of $100.0 million of OG&E s commercial paper borrowings and to provide an additional $50.0 million in revolving credit borrowings. At December 31, 2005, OG&E had approximately $100.0 million in commercial paper borrowings and $0.2 million supporting a letter of credit.

57

The Company s and OG&E 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 back up lines of credit could cause annual fees and borrowing rates to increase if an adverse ratings impact occurs. The impact of any future downgrades would result in an increase in the cost of short-term borrowings but would not result in any defaults or accelerations as a result of the rating changes.

Unlike the Company and Enogex, 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 $400 million in short-term borrowings at any one time for a two-year period beginning January 1, 2005 and ending December 31, 2006.

12. Retirement Plans and Postretirement Benefit Plans

In December 2003, the FASB issued SFAS No. 132 (Revised), Employer s Disclosures about Pension and Postretirement Benefits, an amendment of FASB Statements No. 87, 88 and 106, which revised the disclosure requirements applicable to employers pension plans and other postretirement benefit plans. This Statement requires additional disclosures for defined benefit pension plans and other defined benefit postretirement plans, including disclosures describing the components of net periodic benefit cost recognized during interim periods.

Defined Benefit Pension Plan

All eligible employees of the Company are covered by a non-contributory defined benefit pension plan. For employees hired on or after February 1, 2000, the pension plan is a cash balance plan, under which the Company annually will credit to the employee s account an amount equal to five percent of the employee s annual compensation plus accrued interest. Employees hired prior to February 1, 2000 will receive the greater of the cash balance benefit or a benefit based primarily on years of service and the average of the five highest consecutive years of compensation during an employee s last 10 years prior to retirement, with reductions in benefits for each year prior to age 62 unless the employee s age and years of credited service equal or exceed 80.

It is the Company s policy to fund the plan on a current basis based on the net periodic SFAS No. 87 pension expense as determined by the Company s actuarial consultants. Additional amounts may be contributed from time to time to increase the funded status of the plan. During 2005 and 2004, the Company made contributions to its pension plan of approximately $32.0 million and $69.0 million, respectively, to 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 2006, the Company may contribute up to $90 million to the plan. The expected contribution to the pension plan, anticipated to be in the form of cash, is a discretionary contribution and is not required to satisfy the minimum funding requirements specified by the Employee Retirement Income Security Act of 1974, as amended.

During 2005 and 2004, the Company made contributions to the pension plan and the restoration of retirement income plan that exceeded amounts previously recognized as net periodic pension expense and recorded a net prepaid benefit obligation at December 31, 2005 and 2004 of approximately $88.9 million and $92.0 million, respectively. At December 31, 2005 and 2004, the Company s projected pension benefit obligation exceeded the fair value of the pension plan assets and the restoration of retirement income plan assets by approximately $154.6 million and $123.3 million, respectively. As a result of recording a prepaid benefit obligation and having a funded status where the projected benefit obligations exceeded the fair value of plan assets, provisions of SFAS No. 87 required the recognition of an additional minimum liability in the amount of approximately $181.4 million and $156.6 million, respectively, at December 31, 2005 and 2004. The offset of this entry was an intangible asset and Accumulated Other Comprehensive Income, net of a deferred tax asset; therefore, this adjustment did not impact the results of operations in 2005 or 2004 and did not require a usage of cash and is therefore excluded from the Consolidated Statements of Cash Flows. The amount recorded as an intangible asset equaled the unrecognized prior service cost with the remainder recorded in Accumulated Other Comprehensive Income. The amount in Accumulated Other Comprehensive Income represents a net periodic pension cost to be recognized in the Consolidated Statements of Income in future periods.

The plan s assets consist primarily of investments in mutual funds, U.S. Government securities, listed common stocks and corporate debt. The following table shows, by major category, the percentage of the fair value of the plan assets held at December 31, 2005 and 2004:

	2005	2004
Equity securities	**59 %**	62 %
Debt securities	**36 %**	36 %
Other securities	**5 %**	2 %
Total	**100 %**	100 %

Investment Policies and Strategies

The plan assets are held in a trust which follows an investment policy and strategy designed to maximize the long-term investment returns of the trust at prudent risk levels. Common stocks are used as a hedge against moderate inflationary conditions, as well as for participation in normal economic times. Fixed income investments are utilized for high current income and as a hedge against deflation. 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 Employees Benefit Funds Management Committee (the 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 their respective portfolio. The table below shows the target asset allocation percentages for each major category of plan assets:

Asset Class	**Target Allocation**	**Minimum**	**Maximum**
Domestic Equity	30 %	--- %	60 %
Domestic Mid-Cap Equity	10 %	--- %	10 %
Domestic Small-Cap Equity	10 %	--- %	10 %
International Equity	10 %	--- %	10 %
Fixed Income Domestic	38 %	30 %	70 %
Cash	2 %	--- %	5 %

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 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)**
Fixed Income	Lehman Aggregate Index
Equity Index	S&P 500 Index

Value Equity	Russell 1000 Value Index	Short-term
	S&P 500 Index	Long-term
Growth Equity	Russell 1000 Growth Index	Short-term
	S&P 500 Index	Long-term
Mid-Cap Equity	S&P 400 Midcap Index	
Small-Cap Equity	Russell 2000 Index	
International Equity	Morgan Stanley Capital International Europe, Australia and Far East Index	

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 Service (Moody s), Standard & Poor s Ratings Services (Standard & Poor s) or Fitch Ratings (Fitch). The

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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 S&P 400 Midcap Index, small dividend yield, return on equity at or near the S&P 400 Midcap Index and earnings per share growth rate at or near the S&P 400 Midcap Index. The domestic small-capitalization equity manager will purchase shares of companies with market capitalizations lower that 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 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 Europe, Australia and the Far East Index (EAFE) is the benchmark for comparative performance purposes. The EAFE Index is a market value weighted index comprised of over 1,000 companies traded on the stock markets of Europe, Australia, New Zealand and the Far East. 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. A minimum of 95 percent of the total assets of an equity manager s portfolio must be allocated to the equity markets. Options or financial futures may not be purchased unless prior approval of the 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.

Restoration of Retirement Income Plan

The Company provides a restoration of retirement income plan to those participants in the Company s pension plan whose benefits are subject to certain limitations under the Code. The benefits payable under this restoration of retirement income plan are equivalent to the amounts that would have been payable under the pension plan but for these limitations. The restoration of retirement income plan is intended to be an unfunded plan.

Postretirement Benefit Plans

In addition to providing pension benefits, the Company provides certain medical and life insurance benefits for eligible retired members (postretirement benefits). 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 age 55 with 10 years of vesting service at the time of retirement are entitled to these postretirement benefits. Employees hired on or after February 1, 2000, are not entitled to postretirement medical benefits but are entitled to postretirement life insurance benefits. Eligible retirees must contribute such amount as the Company specifies from time to time toward the cost of coverage for postretirement benefits. The benefits are subject to deductibles, co-payment provisions and other limitations. OG&E charges to expense the SFAS No. 106, Employers Accounting for Postretirement Benefits other than Pensions, costs and includes an annual amount as a component of the cost-of-service in future ratemaking proceedings.

The details of the funded status of the pension plan (including the restoration of retirement income plan) and the postretirement benefit plans and the amounts included in the Consolidated Balance Sheets are as follows:

60

Projected Benefit Obligations

	Pension Plan and Restoration of Retirement Income Plan		Postretirement Benefit Plans	
(In millions)	**2005**	2004	**2005**	2004
Beginning obligations	**$ (548.2)**	$ (485.4)	**$ (192.3)**	$ (181.1)
Service cost	**(19.1)**	(16.9)	**(3.2)**	(3.0)
Interest cost	**(30.3)**	(29.7)	**(10.5)**	(11.1)
Participants contributions	**---**	---	**(3.9)**	(3.0)

Plan changes / other	**---**	(7.2)	**---**	---
Actuarial losses	**(38.9)**	(56.0)	**(12.0)**	(7.0)
Benefits paid	**42.5**	47.0	**13.7**	12.9
Ending obligations	**$ (594.0)**	$ (548.2)	**$ (208.2)**	$ (192.3)

Fair Value of Plans Assets

	Pension Plan and Restoration of Retirement Income Plan		Postretirement Benefit Plans	
(In millions)	**2005**	2004	**2005**	2004
Beginning fair value	**$ 424.9**	$ 353.6	**$ 64.0**	$ 56.0
Actual return on plans assets	**23.9**	46.6	**4.6**	9.3
Employer contributions	**33.1**	71.7	**8.4**	8.6
Participants contributions	**---**	---	**3.9**	3.0
Benefits paid	**(42.5)**	(47.0)	**(13.7)**	(12.9)
Ending fair value	**$ 439.4**	$ 424.9	**$ 67.2**	$ 64.0

Net Periodic Benefit Cost

	Pension Plan and Restoration of Retirement Income Plan			Postretirement Benefit Plans		
(In millions)	**2005**	2004	2003	**2005**	2004	2003
Service cost	**$ 19.1**	$ 16.9	$ 15.2	**$ 3.2**	$ 3.0	$ 3.0
Interest cost	**30.3**	29.7	29.2	**10.5**	11.1	10.9
Return on plan assets	**(34.2)**	(31.6)	(24.3)	**(5.5)**	(5.5)	(5.5)
Amortization of transition obligation	**---**	---	---	**2.7**	2.7	2.7
Amortization of net loss	**14.7**	11.9	13.2	**5.0**	4.9	3.4
Amortization of unrecognized prior service cost	**6.3**	6.3	5.8	**2.1**	2.1	2.1
Net periodic benefit cost	**$ 36.2**	$ 33.2	$ 39.1	**$ 18.0**	$ 18.3	$ 16.6

The capitalized portion of the net periodic pension benefit cost was approximately $9.3 million, $8.4 million and $5.8 million at December 31, 2005, 2004 and 2003, respectively. The capitalized portion of the net periodic postretirement benefit cost was approximately $4.7 million, $5.0 million and $2.6 million at December 31, 2005, 2004 and 2003, respectively.

Funded Status of Plans

	Pension Plan and Restoration of Retirement Income Plan		Postretirement Benefit Plans	
(In millions)	**2005**	2004	**2005**	2004
Funded status of the plans	**$ (154.6)**	$ (123.3)	**$ (141.0)**	$ (128.3)
Unrecognized net loss	**210.1**	175.6	**71.3**	63.4
Unrecognized prior service cost	**33.4**	39.7	**7.1**	9.2
Unrecognized transition obligation	**---**	---	**19.2**	22.0
Net amount recognized	**$ 88.9**	$ 92.0	**$ (43.4)**	$ (33.7)

Amounts recognized in the Consolidated Balance Sheets consist of:

	Pension Plan and Restoration of Retirement Income Plan	
(In millions)	**2005**	2004
Prepaid benefit obligation	**$ 90.2**	$ 92.7
Accrued pension and benefit obligations	**(182.8)**	(157.3)
Intangible asset - unamortized prior service cost	**32.8**	38.0
Accumulated deferred tax asset	**57.5**	45.9
Accumulated other comprehensive loss, net of tax	**91.2**	72.7
Net amount recognized	**$ 88.9**	$ 92.0

Rate Assumptions

	Pension Plan			Postretirement Benefit Plans		
	2005	2004	2003	**2005**	2004	2003
Discount rate	**5.50%**	5.75%	6.25%	**5.50%**	5.75%	6.25%
Rate of return on plans assets	**8.50%**	8.75%	8.75%	**8.50%**	8.75%	8.75%
Compensation increases	**4.50%**	4.50%	4.50%	**4.50%**	4.50%	4.50%
Assumed health care cost trend:						
Initial trend	**N/A**	N/A	N/A	**9.00%**	10.00%	11.00%
Ultimate trend rate	**N/A**	N/A	N/A	**4.50%**	4.50%	4.50%
Ultimate trend year	**N/A**	N/A	N/A	**2011**	2010	2010

N/A - not applicable

The overall expected rate of return on plan assets assumption was decreased from 8.75 percent in 2004 to 8.50 percent in 2005 in determining net periodic pension cost. 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.

The Company expects to pay benefits related to its pension plan and restoration of retirement income plan of approximately $64.6 million in 2006, $61.6 million in 2007, $64.0 million in 2008, $64.6 million in 2009, $61.8 million in 2010 and an aggregate of $299.1 million in years 2011 to 2015. These expected benefits were 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.

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 nine percent in 2006 with the rates decreasing in subsequent years by one percentage point per year through 2010. A one-percentage point change in the assumed health care cost trend rate would have the following effects:

ONE-PERCENTAGE POINT INCREASE *(In millions)*	**2005**	2004	2003
Effect on aggregate of the service and interest cost components	**$ 1.8**	$ 1.9	$ 1.9
Effect on accumulated postretirement benefit obligations	**26.9**	24.2	23.1

ONE-PERCENTAGE POINT DECREASE *(In millions)*	**2005**	2004	2003
Effect on aggregate of the service and interest cost components	**$ 1.5**	$ 1.5	$ 1.5
Effect on accumulated postretirement benefit obligations	**22.0**	19.8	18.9

Medicare Prescription Drug, Improvement and Modernization Act of 2003

On December 8, 2003, President Bush signed into law the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (the Medicare Act). The Medicare Act expanded Medicare to include, for the first time, coverage for prescription drugs. In May 2004, the FASB issued FASB Staff Position No. FAS 106-2, Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003. FAS 106-2 provides guidance on the accounting for the effects of the Medicare Act for employers that sponsor postretirement heath care plans that provide prescription drug benefits. FAS 106-2 also requires those employers to provide certain disclosures regarding the effect of the federal subsidy provided by the Medicare Act. The Company adopted this new standard effective July 1, 2004 with retroactive application to the date of the Medicare Act s enactment. Management expects that the accumulated plan benefit obligation (APBO) for the Company s postretirement medical plan will be reduced by approximately $29.8 million as a result of savings to the Company s postretirement medical plan resulting from the Medicare Act, which will reduce the Company s costs for its postretirement medical plan by approximately $5.2 million annually. The $5.2 million in annual savings is comprised of a reduction of approximately $3.1 million from amortization of the $29.8 million gain due to the reduction of the APBO, a reduction in the interest cost on the APBO of approximately $1.7 million and a reduction in the service cost due to the subsidy of approximately $0.4 million.

The Company expects to pay gross benefits payments related to its postretirement benefit plans, including prescription drug benefits, of approximately $11.3 million in 2006, $11.4 million in 2007, $12.3 million in 2008, $13.1 million in 2009, $13.9 million in 2010 and an aggregate of $79.8 million in years 2011 to 2015. The Company expects to receive federal subsidy receipts provided by the Medicare Act of approximately $1.0 million in 2006, $1.1 million in 2007, $1.3 million in 2008, $1.4 million in 2009, $1.5 million in 2010 and an aggregate of $9.1 million in years 2011 to 2015. The Company did not receive any federal subsidy receipts in 2005; however, the Company s 2005 SFAS No. 106 expense reflects credit for the expected future subsidies, thus reducing the expense.

Defined Contribution Plan

The Company provides a defined contribution savings plan. Each regular full-time employee of the Company or an affiliate is eligible to participate in the plan immediately. All other employees of the Company or an affiliate are eligible to become participants in the plan after completing one year of service as defined in the plan. Participants may contribute each pay period any whole percentage between two percent and 19 percent of their compensation, as defined in the plan, for that pay period. Contributions of the first six percent of compensation are called Regular Contributions and any contributions over six percent of compensation are called Supplemental Contributions. The Company contributes to the Plan each pay period on behalf of each participant an amount equal to 50 percent of the participant s Regular Contributions for participants whose employment or re-employment date, as defined in the plan, occurred before February 1, 2000 and who have less than 20 years of service, as defined in the plan, and an amount equal to 75 percent of the participant s Regular Contributions for participants whose employment or re-employment date occurred before February 1, 2000 and who have 20 or more years of service. For participants whose employment or re-employment date occurred on or after February 1, 2000, the Company shall contribute 100 percent of the Regular Contributions deposited during such pay period by such participant. No Company contributions are made with respect to a participant s Supplemental Contributions or with respect to a participant s Regular 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. The Company s contribution which is allocated for investment to the OGE Energy Corp. Common Stock Fund may be made in shares of the Company s common stock or in cash which is used to invest in the Company s common stock. The Company contributed approximately $6.7 million, $6.2 million and $5.6 million during 2005, 2004 and 2003, respectively, to the defined contribution plan.

Deferred Compensation Plan

The Company provides a deferred compensation 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 defined contribution plan contributions.

Eligible employees who enroll in the plan may elect to defer up to a maximum of 70 percent of base salary and 100 percent of bonus awards; however, the Benefits Committee, appointed by the Benefits Oversight Committee (which consists of at least two members appointed by the Board of Directors) may, at its discretion, permit participants to elect a deferral percentage of base salary and bonus awards based on the deferral percentage elected for a year under the defined contribution plan, with such deferrals to start when maximum deferrals to the defined contribution 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 provide for the match that would have been made under the defined contribution plan had such deferrals been made under that plan without regard to the statutory limitations on elective deferrals and matching contributions applicable to the defined contribution plan. In addition, the Benefits Committee may award discretionary employer contribution credits to a participant under the plan. The Company accounts for the contributions related to the Company s executive officers in this plan as Accrued Pension and 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. The supplemental executive retirement plan is intended to be an unfunded plan and not subject to the benefit limits imposed by the Code.

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13. Report of Business Segments

The Company s Electric Utility operations are conducted through OG&E, a regulated utility engaged in the generation, transmission, distribution and sale of electric energy. The Company s Natural Gas Pipeline operations are conducted through Enogex. Enogex is engaged in the transportation and storage of natural gas, the gathering and processing of natural gas and the marketing of natural gas. Other Operations for the year ended December 31, 2005 primarily includes unallocated corporate expenses, interest expense on commercial paper and interest expense on long-term debt. Other Operations for the year ended December 31, 2004 and 2003 primarily includes unallocated corporate expenses, interest expense to unconsolidated affiliate and interest expense on commercial paper. Intersegment revenues are recorded at prices comparable to those of unaffiliated customers and are affected by regulatory considerations. The following tables summarize the results of the Company s business segments for the years ended December 31, 2005, 2004 and 2003.

2005 *(In millions)*	Electric Utility	Natural Gas Pipeline (A)	Other Operations	Intersegment	Total
Operating revenues	**$ 1,720.7**	**$4,369.1**	**$ ---**	**$ (141.6)**	**$5,948.2**
Cost of goods sold	**994.2**	**4,111.2**	**---**	**(142.3)**	**4,963.1**
Gross margin on revenues	**726.5**	**257.9**	**---**	**0.7**	**985.1**
Other operation and maintenance	**309.2**	**100.5**	**(10.9)**	**---**	**398.8**
Depreciation	**134.4**	**43.9**	**7.8**	**---**	**186.1**
Taxes other than income	**50.7**	**15.8**	**3.2**	**---**	**69.7**

Operating income (loss)	**232.2**	**97.7**	**(0.1)**	**0.7**	**330.5**
Other income (loss)	**(2.3)**	**0.8**	**1.7**	**---**	**0.2**
Other expense	**(3.0)**	**(0.3)**	**(2.7)**	**---**	**(6.0)**
Interest income	**2.6**	**2.9**	**1.7**	**(3.7)**	**3.5**
Interest expense	**(47.2)**	**(32.6)**	**(14.2)**	**3.7**	**(90.3)**
Income tax expense (benefit)	**52.6**	**23.6**	**(4.7)**	**0.3**	**71.8**
Income (loss) from continuing operations	**129.7**	**44.9**	**(8.9)**	**0.4**	**166.1**
Income from discontinued operations	**---**	**44.9**	**---**	**---**	**44.9**
Net income (loss)	**$ 129.7**	**$ 89.8**	**$ (8.9)**	**$ 0.4**	**$ 211.0**
Total assets	**$ 3,255.0**	**$1,680.1**	**$ 1,962.0**	**$ (1,998.2)**	**$4,898.9**
Capital expenditures	**$ 249.1**	**$ 36.2**	**$ 13.4**	**$ ---**	**$ 298.7**

(A) Natural Gas Pipeline s operations consist of three related businesses: Transportation and Storage, Gathering and Processing and Marketing. The following table provides supplemental Natural Gas Pipeline information.

2005	Transportation and Storage	Gathering and Processing	Marketing	Eliminations	Total
(In millions)					
Operating revenues	**$ 246.4**	**$ 681.2**	**$ 3,995.3**	**$ (553.8)**	**$4,369.1**
Operating income (loss)	**$ 37.1**	**$ 66.8**	**$ (6.2)**	**$ ---**	**$ 97.7**
Income (loss) from continuing operations	**$ 43.5**	**$ 43.4**	**$ (6.0)**	**$ (36.0)**	**$ 44.9**

(B) In March 2005, Enogex corrected its procedure for accounting for park and loan transactions (natural gas storage transactions) during 2004 that resulted from an incorrect change in an accounting procedure implemented during 2004. The incorrect procedure affected the timing of recognition of revenue and income from park and loan transactions and resulted in a temporary overstatement of operating revenues without the associated expense until the transaction was completed and the expense recognized. As a result of this correction, Enogex recorded a pre-tax charge of approximately $7.7 million ($4.7 million after tax or $0.05 per share) as a reduction in Operating Revenues in the Condensed Consolidated Statement of Income and a corresponding $7.7 million decrease in Current Price Risk Management Assets in the Condensed Consolidated Balance Sheet during the three months ended March 31, 2005.

2004	Electric Utility	Natural Gas Pipeline (A)	Other Operations	Intersegment	Total
(In millions)					
Operating revenues	$ 1,578.1	$3,421.7	$ ---	$ (95.4)	$4,904.4
Cost of goods sold	914.2	3,143.6	---	(94.7)	3,963.1
Gross margin on revenues	663.9	278.1	---	(0.7)	941.3
Other operation and maintenance	301.9	97.3	(11.2)	---	388.0

Depreciation	122.7	44.0	8.3	---	175.0
Impairment of assets	---	7.8	---	---	7.8
Taxes other than income	47.0	16.4	3.3	---	66.7
Operating income (loss)	192.3	112.6	(0.4)	(0.7)	303.8
Other income	5.8	4.5	1.5	---	11.8
Other expense	(2.7)	(0.3)	(2.1)	---	(5.1)
Interest income	2.7	3.2	1.3	(2.3)	4.9
Interest expense	(37.5)	(32.2)	(23.4)	2.3	(90.8)
Income tax expense (benefit)	53.0	33.1	(8.7)	(0.3)	77.1
Income (loss) from continuing operations	107.6	54.7	(14.4)	(0.4)	147.5
Income from discontinued operations	---	6.0	---	---	6.0
Net income (loss)	$ 107.6	$ 60.7	$ (14.4)	$ (0.4)	$ 153.5
Total assets	$ 3,057.7	$1,740.3	$ 1,717.1	$ (1,712.2)	$4,802.9
Capital expenditures	$ 391.2	$ 31.2	$ 8.5	$ ---	$ 430.9

(A) Natural Gas Pipeline s operations consist of three related businesses: Transportation and Storage, Gathering and Processing and Marketing. The following table provides supplemental Natural Gas Pipeline information.

2004 *(In millions)*	Transportation and Storage	Gathering and Processing	Marketing	Eliminations	Total
Operating revenues	$ 249.4	$ 566.5	$ 3,056.1	$ (450.3)	$ 3,421.7
Operating income	$ 46.9	$ 56.2	$ 9.5	$ ---	$ 112.6
Income from continuing operations	$ 52.9	$ 37.8	$ 5.9	$ (41.9)	$ 54.7

2003 *(In millions)*	Electric Utility	Natural Gas Pipeline (A)	Other Operations	Intersegment	Total
Operating revenues	$1,517.1	$ 2,306.2	$ ---	$ (65.9)	$ 3,757.4
Cost of goods sold	837.3	2,070.2	---	(65.9)	2,841.6
Gross margin on revenues	679.8	236.0	---	---	915.8
Other operation and maintenance	294.8	87.4	(14.3)	---	367.9
Depreciation	121.8	40.9	10.9	---	173.6
Impairment of assets	---	9.2	1.0	---	10.2
Taxes other than income	46.9	16.4	2.9	---	66.2
Operating income (loss)	216.3	82.1	(0.5)	---	297.9
Other income	0.6	0.7	0.7	---	2.0
Other expense	(3.2)	(1.6)	(2.8)	---	(7.6)
Interest income	0.7	0.8	1.7	(1.9)	1.3

Interest expense	(38.8)	(34.1)	(21.3)	1.9	(92.3)
Income tax expense (benefit)	60.2	19.8	(9.2)	---	70.8
Income (loss) from continuing operations	115.4	28.1	(13.0)	---	130.5
Income from discontinued operations	---	4.7	---	---	4.7
Income (loss) before cumulative effect of change in accounting principle	115.4	32.8	(13.0)	---	135.2
Cumulative effect on prior years of change in accounting principle, net of tax	---	(5.9)	0.5	---	(5.4)
Net income (loss)	$ 115.4	$ 26.9	$ (12.5)	$ ---	$ 129.8
Total assets	$2,737.5	$ 1,561.2	$ 1,716.4	$ (1,454.7)	$ 4,560.4
Capital expenditures	$ 148.7	$ 27.5	$ 4.6	$ ---	$ 180.8

(A) Natural Gas Pipeline s operations consist of three related businesses: Transportation and Storage, Gathering and Processing and Marketing. The following table provides supplemental Natural Gas Pipeline information.

2003 *(In millions)*	Transportation and Storage	Gathering and Processing	Marketing	Eliminations	Total
Operating revenues	$ 177.6	$ 511.7	$ 1,963.7	$ (346.8)	$ 2,306.2
Operating income	$ 55.1	$ 14.0	$ 13.0	$ ---	$ 82.1
Income from continuing operations	$ 20.4	$ 8.4	$ 7.9	$ (8.6)	$ 28.1

14. Commitments and Contingencies

Capital Expenditures

The Company s capital expenditures are estimated at approximately: 2006 $307.0 million, 2007 $248.0 million and 2008 - $250.0 million.

Operating Lease Obligations

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

(In millions)	2006	2007	2008	2009	2010	2011 and Beyond
Operating lease obligations						
OG&E railcars	$ 4.3	$ 4.0	$ 3.9	$ 3.8	$ 3.7	$ 36.6
Enogex noncancellable operating leases	3.3	0.9	0.1	0.1	0.1	0.1
Total operating lease obligations	$ 7.6	$ 4.9	$ 4.0	$ 3.9	$ 3.8	$ 36.7

Payments for operating lease obligations were approximately $9.7 million, $9.7 million and $9.8 million in 2005, 2004 and 2003, respectively.

OG&E Railcar Lease Agreement

At December 31, 2005, OG&E had a noncancellable operating lease with purchase options, covering 1,464 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 automatic fuel adjustment clauses. On December 29, 2005, OG&E entered into a new lease agreement for railcars effective February 1, 2006 with a new lessor as described below. At the end of the new lease term which is January 31, 2011, 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 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 approximately $29.9 million. OG&E is also required to maintain 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.

Public Utility Regulatory Policy Act of 1978

OG&E has entered into agreements with three qualifying cogeneration facilities having initial terms of three to 32 years. These contracts were entered into pursuant to the Public Utility Regulatory Policy Act of 1978 (PURPA). Stated generally, PURPA and the regulations thereunder promulgated by the FERC require OG&E to purchase power generated in a manufacturing process from a qualified cogeneration facility (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. OG&E has approximately 430 MW s of QF contracts that will expire at the end of 2007, unless extended by OG&E. For one of these QF contracts, OG&E purchases 100 percent of electricity generated by the QF. For the other QF contract, OG&E can purchase up to 17 percent of electricity generated by the QF. In addition, effective September 1, 2004, OG&E entered into a new 15-year power purchase agreement for 120 MW s with PowerSmith in which OG&E purchases 100 percent of electricity generated by PowerSmith.

During 2005, 2004 and 2003, OG&E made total payments to cogenerators of approximately $183.8 million, $203.5 million and $203.0 million, respectively, of which approximately $95.5 million, $155.3 million and $164.7 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. The future minimum capacity payments under the contracts are approximately: 2006 $98.6 million, 2007 $97.1 million, 2008 $95.4 million, 2009 $93.6 million and 2010 $91.7 million. The minimum capacity payment amounts for 2008 through 2010 assume OG&E elects to extend certain cogeneration contracts, which otherwise expire at the end of 2007.

Fuel Minimum Purchase Commitments

OG&E purchased necessary fuel supplies of coal and natural gas for its generating units of approximately $163.5 million, $166.5 million and $157.3 million for the years ended December 31, 2005, 2004 and 2003, respectively. OG&E has

entered into purchase commitments of necessary fuel supplies of approximately: 2006 $184.4 million, 2007 $169.4 million, 2008 $189.6 million, 2009 $99.0 million, 2010 $103.3 million and 2011 and Beyond $86.8 million.

Natural Gas Units

OG&E utilized a request for bid (RFB) to acquire approximately 30 percent of its projected annual natural gas requirements for 2006. All of these contracts are tied to various gas price market indices and most will expire in December 2006. Additional natural gas supply for the summer of 2006 will be secured through a new RFB issued in the first quarter of 2006. OG&E will meet additional natural gas requirements with monthly and daily purchases as required.

Natural Gas Storage Facility Agreement with Central Oklahoma Oil and Gas Corp.

In 1998, Enogex entered into a Storage Lease Agreement (the Agreement) with Central Oklahoma Oil and Gas Corp. (COOG). In 1999 a dispute arose as to whether the natural gas deliverability for the Stuart Storage Facility was being provided to Enogex by COOG and these issues were submitted to arbitration in the fourth quarter of 2001 resulting in an arbitration award against COOG and in favor of Enogex in the amount of approximately $23.3 million (the COOG Judgment).

In 2002, Enogex exercised the asset purchase option provided in the Agreement and title to the Stuart Storage Facility was transferred to Enogex. In addition, under a related transaction, Natural Gas Storage Corporation (NGSC), an affiliate of COOG, went into default relating to a $12 million secured loan (NGSC Loan) with the Company.

In 2002, a legal proceeding was filed by COOG and NGSC against the Company and Enogex in Texas Natural Gas Storage Corporation and Central Oklahoma Oil and Gas Corp. v. OGE Energy Corp. and Enogex, Case No. 2002-38894; District Court of Harris County, Texas. COOG and NGSC stated a claim for declaratory judgment and breach of contract, asserting that NGSC was not obligated to make payments on the NGSC Loan. The Company objected to being sued in Texas based on lack of jurisdiction over the Company. Enogex responded to the allegations, asserting that the disputed issues have already been properly determined by the Arbitration Panel and, therefore, such action was improper. In 2003, the Texas Court granted Enogex s request for arbitration. In 2004, COOG, NGSC, Enogex and the Company submitted remaining issues to a second arbitration panel. The arbitration panel rendered a decision in the Company s favor for approximately $5.0 million related to the outstanding NGSC Loan (the NGSC Judgment). After the arbitration award, the plaintiffs, in the pending Texas action, amended the petition and moved to dismiss Enogex from the suit. The court granted the dismissal by order dated January 26, 2005. On September 30, 2005, an order was entered by the Texas Court disposing of the remaining and entire Texas action based on a lack of jurisdiction.

In 2003, the Company and Enogex brought separate complaints in the Western District of Oklahoma Federal Court against the individual shareholders of COOG and NGSC Enogex Inc. v John C. Thrash, John F. Thrash and Robert R. Voorhees, Jr., Case No. CIV-03-0388-L; and OGE Energy Corp. and Enogex Inc. v John C. Thrash, John F. Thrash and Robert R. Voorhees, Jr., Case No. CIV 03-0389-L. The Company and Enogex each stated claims for fraudulent transfer and breach of fiduciary duty. A jury trial was held in 2004 and the jury ruled in favor of the Company and Enogex for approximately $6.6 million (Thrash Fraudulent Transfer Judgment). In April 2005, the defendants filed an appeal in the Tenth Circuit Court of Appeals and on September 14, 2005, the defendants posted a cash bond for approximately $6.9 million to stay the execution of the Thrash Fraudulent Transfer Judgment pending appeal. On December 30, 2005, the parties reached a settlement of the Thrash Fraudulent Transfer Judgment, the COOG Judgment, the NGSC Judgment and related matters. The individual defendants agreed to pay approximately $5.2 million (the Settlement Agreement) from the cash bond paid into the appeal court. In addition, the parties agreed to dismiss the pending appeal of the Thrash Fraudulent Transfer Judgment to the Tenth Circuit. The Settlement Agreement has been accounted for as a gain contingency and will be recognized in the Company s financial statements when the Settlement Agreement has been received which is expected in the first quarter of 2006. Upon payment of the Settlement Agreement, the Company will consider these matters closed.

Natural Gas Measurement Cases

United States of America ex rel., Jack J. Grynberg v. Enogex Inc., Enogex Services Corporation and OG&E. (United States District Court for the Western District of Oklahoma, Case No. CIV-97-1010-L.) United States of America ex rel., Jack J. Grynberg v. Transok Inc. et al. (United States District Court for the Eastern District of Louisiana, Case No. 97-2089; United States District Court for the Western District of Oklahoma, Case No. 97-1009M.). On June 15, 1999, the Company was served with Plaintiff s complaint, which is a qui tam action under the False Claims Act. Plaintiff Jack J. Grynberg, as individual relator on behalf of the United States Government, alleges: (i) each of the named defendants have improperly or intentionally mismeasured gas (both volume and British thermal unit (Btu) content) purchased from federal

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and Indian lands which have resulted in the under-reporting and underpayment of gas royalties owed to the Federal Government; (ii) certain provisions generally found in gas purchase contracts are improper; (iii) transactions by affiliated companies are not arms-length; (iv) excess processing cost deduction; and (v) failure to account for production separated out as a result of gas processing. Grynberg seeks the following damages: (a) additional royalties which he claims should have been paid to the Federal Government, some percentage of which Grynberg, as relator, may be entitled to recover; (b) treble damages; (c) civil penalties; (d) an order requiring defendants to measure the way Grynberg contends is the better way to do so; and (e) interest, costs and attorneys fees.

In qui tam actions, the United States Government can intervene and take over such actions from the relator. The Department of Justice, on behalf of the United States Government, decided not to intervene in this action.

Plaintiff filed over 70 other cases naming over 300 other defendants in various Federal Courts across the country containing nearly identical allegations. The Multidistrict Litigation Panel entered its order in late 1999 transferring and consolidating for pretrial purposes approximately 76 other similar actions filed in nine other Federal Courts. The consolidated cases are now before the United States District Court for the District of Wyoming.

In October 2002, the Court granted the Department of Justice s motion to dismiss certain of Plaintiff s claims and issued an order dismissing Plaintiff s valuation claims against all defendants. Various procedural motions have been filed. Discovery is proceeding on limited jurisdictional issues as ordered by the Court. A hearing on the defendants motions to dismiss for lack of subject matter jurisdiction, including public disclosure, original source and voluntary disclosure requirements was held March 17 - 18, 2005. A ruling in this case by the special master was received in May 2005 which dismissed OG&E and all Enogex parties named in these proceedings. This ruling has been appealed to the District Court of Wyoming. An oral argument on this appeal to the District Court was made on December 9, 2005 but there is no ruling in this case to date. The Company intends to vigorously defend this action. At this time, the Company is unable to provide an evaluation of the likelihood of an unfavorable outcome and an estimate of the amount or range of potential loss to the Company.

Will Price (Price I) On September 24, 1999, various subsidiaries of the Company were served with a class action petition filed in United States District Court, State of Kansas by Quinque Operating Company and other named plaintiffs, alleging mismeasurement of natural gas on non-federal lands. On April 10, 2003 the Court entered an order denying class certification. On May 12, 2003, Plaintiffs (now Will Price, Stixon Petroleum, Inc., Thomas F. Boles and the Cooper Clark Foundation, on behalf of themselves and other royalty interest owners) filed a motion seeking to file an amended petition and the court granted the motion on July 28, 2003. In this amended petition, OG&E and Enogex Inc. were omitted from the case. Two subsidiaries of Enogex remain as defendants. The Plaintiffs amended petition alleges that approximately 60 defendants, including two Enogex subsidiaries, have improperly measured natural gas. The amended petition reduces the claims to: (1) mismeasurement of volume only; (2) conspiracy, unjust enrichment and accounting; (3) a putative Plaintiffs class of only royalty owners; and (4) gas measured in three specific states. Discovery on class certification is proceeding. A hearing on class certification issues was held April 1, 2005. The Company intends to vigorously defend this action. At this time, the Company is unable to provide an evaluation of the likelihood of an unfavorable outcome and an estimate of the amount or range of potential loss to the Company.

Will Price (Price II) On May 12, 2003, the Plaintiffs (same as those in Price I above) filed a new class action petition (Price II) in the District Court of Stevens County, Kansas, relating to wrongful Btu analysis against natural gas pipeline owners and operators, naming the same defendants as in the amended petition of the Price I case. Two Enogex subsidiaries were served on August 4, 2003. The Plaintiffs seek to represent a class of only royalty owners either from whom the defendants had purchased natural gas or measured natural gas since January 1, 1974 to the present. The class action petition alleges improper analysis of gas heating content. In all other respects, the Price II petition appears to be the same as the amended petition in Price I. Discovery on class certification is proceeding. A hearing on class certification issues was held April 1, 2005. The Company intends to vigorously defend this action. At this time, the Company is unable to provide an evaluation of the likelihood of an unfavorable outcome and an estimate of the amount or range of potential loss to the Company.

Agreement with Cheyenne Plains Gas Pipeline Company, L.L.C.

OERI and Cheyenne Plains Gas Pipeline Company, L.L.C. are parties to a firm transportation services agreement dated April 14, 2004. The Cheyenne Plains Pipeline provides interstate gas transportation services in Wyoming, Colorado and Kansas with a capacity of 560,000 decatherms/day (Dth/day). Effective January 1, 2006, the capacity on the Cheyenne Plains Pipeline increased to 730,000 Dth/day. OERI reserved 60,000 Dth/day of firm capacity on the Cheyenne Plains Pipeline for 10 years. Such reservation provides OERI access to significant additional natural gas supplies in the Rocky

Mountain production basins. OERI pays a demand fee of approximately $7.5 million annually for this capacity. OERI incurred a loss of approximately $3.6 million during 2005 related to its Cheyenne Plains position as a result of unfavorable market conditions for the capacity primarily due to the earlier than expected in-service date for the project and the associated lack of upstream gas supply and pipeline infrastructure to deliver gas to the Cheyenne hub for 2005. If the market conditions reflected in the current forward market price quotes continue for 2006, OERI expects to record a loss of approximately $1.4 million in 2006.

G.M. Oil Properties Litigation

On March 8, 2005, Enogex was served with a putative class action filed by G.M. Oil Properties, Inc. in the District Court of Comanche County, Oklahoma. The petition alleges that Enogex exercises a monopoly power with respect to its gathering facilities within the state of Oklahoma. The petition further alleges that, due to the alleged monopoly power, Enogex has caused damage to the plaintiff and other small gas producers and marketers. A settlement of this case has been reached with the named plaintiffs and the case brought by the named plaintiffs will be dismissed with prejudice. Pursuant to the settlement, a certain segment of gathering pipeline will be sold to G.M. Oil Properties with the Company recognizing the resulting gain of less than $0.1 million.

Pipeline Rupture

On May 10, 2005, a natural gas pipeline rupture occurred on an Enogex facility within the ANR Pipeline, Inc. (ANR) plant site in Custer County, near Clinton, Oklahoma, resulting in an explosion and fire. Several companies have operations at the site which is operated by ANR, a subsidiary of El Paso Corporation. No injuries were reported as a result of the incident. The Enogex pipeline equipment at the site was isolated and the flow of gas to the site was shut off. Investigation of the incident and the cause thereof is ongoing. The site is near the location of the former Enogex Custer gas processing plant closed in 2002. Although temporarily disrupted, pipeline operations continue at the location. It is anticipated that any third party damages related to this incident will not be material to the Company as they will be covered by insurance following payment of the deductible, which deductible has been accrued in the Company s Consolidated Financial Statements.

Farris Buser Litigation

On July 22, 2005, Enogex along with certain other unaffiliated co-defendants were served with a purported class action which had been filed on February 7, 2005 by Farris Buser and other named plaintiffs in the District Court of Canadian County, Oklahoma. The plaintiffs own royalty interests in certain oil and gas producing properties and allege they have been under-compensated by the named defendants, including the Enogex companies, relating to the sale of liquid hydrocarbons recovered during the transportation of natural gas from the plaintiffs wells. The plaintiffs assert breach of contract, implied covenants, obligation, fiduciary duty, unjust enrichment, conspiracy and fraud causes of action and claim actual damages in excess of $10,000, plus attorneys fees and costs, and punitive damages in excess of $10,000. The Enogex companies filed a motion to dismiss which was granted on November 18, 2005, subject to the plaintiffs right to conduct discovery and the possible re-filing of their allegations in the petition against Enogex companies. The court-established re-filing deadline has been extended by order of the court until May 17, 2006. On September 19, 2005, the co-defendants, BP America, Inc. and BP America Production Co., filed a cross claim against Enogex Products Corporation (Products) seeking indemnification and/or contribution from Products based upon the 1997 sale of a third party interest in one of Products natural gas processing plants. Based on its investigation to date, the Company believes these claims and cross claims in this lawsuit are without merit and intends to vigorously defend this case.

Kaiser-Francis Litigation

OG&E was sued by Kaiser-Francis Oil Company in District Court, Blaine County, Oklahoma. This case has been pending for more than 13 years. Plaintiff alleged that OG&E breached the terms of numerous contracts covering approximately 60 wells by failing to purchase gas from Plaintiff in amounts set forth in the contracts. Plaintiff sought $20.0 million in take-or-pay damages and $1.8 million in underpayment damages. Over the objection and unsuccessful appeal by OG&E, Plaintiff was permitted to amend its petition to include a claim based on theories of tort. Specifically, Plaintiff alleged that OG&E engaged in tortious conduct by, among other things, falsifying documents, sponsoring false testimony and putting forward legal defenses, which were known by OG&E to be without merit. If successful, Plaintiff believed that these theories could give Plaintiff a basis to seek punitive damages. This lawsuit was stayed from June 2002 through February 2005 during the appeal of a similar case filed by Kaiser-Francis in Grady County, Oklahoma.

On January 3, 2006, the trial court granted OG&E s motion for partial summary judgment on Plaintiff s tort claim. This ruling struck from the lawsuit Plaintiff s claim of (i) approximately $4.7 million in tort damages; and (ii) approximately $11 million in punitive damages. On January 13, 2006, at a court-ordered settlement conference, a settlement was reached in the Blaine County case whereby OG&E agreed to pay $8.9 million to Kaiser-Francis. The suit was dismissed with prejudice on January 18, 2006 and this case is now closed. OG&E believes that the settlement amount is recoverable through its regulated electric rates.

In the similar case in Grady County, Oklahoma, Kaiser-Francis alleged that OG&E breached the terms of several gas purchase contracts in amounts set forth in the contracts. As previously reported in the Company s Form 10-Q for the quarter ended September 30, 2005, the case was settled and is now closed.

Calpine Corporation Bankruptcy

Calpine Corporation, Calpine Energy Services, L.P., and several other affiliates (collectively Calpine) voluntarily filed for Chapter 11 bankruptcy protection from creditors on December 20, 2005 (Case No. 05-60200 (BRL)) United States Bankruptcy Court, S.D. of New York. Enogex provides natural gas transportation services pursuant to long term contracts to two Calpine-owned power generation plants in Oklahoma. At this point, Calpine is continuing to operate the plants, request services pursuant to the contracts and make the monthly payments under its agreements with Enogex; however, whether Calpine in its bankruptcy proceedings will ultimately reject these agreements with Enogex is unknown.

A Calpine-owned power generation plant in Oklahoma is contractually obligated to provide capacity and energy to OG&E. The Calpine plant also pays, through the Southwest Power Pool (SPP), for transmission services provided by OG&E. OG&E expects both arrangements to remain in effect; however, whether Calpine in its bankruptcy proceedings will ultimately reject these agreements with OG&E is unknown.

Guarantees

At December 31, 2005 in the event Moody s or Standard & Poor s were to lower Enogex s senior unsecured debt rating to a below investment grade rating, Enogex would be required to post approximately $16.8 million of collateral to satisfy its obligation under its financial and physical contracts.

Environmental Laws and Regulations

Approximately $5.0 million of the Company s capital expenditures budgeted for 2006 are to comply with environmental laws and regulations. The Company s management believes that all of its operations are in substantial compliance with present federal, state and local environmental standards. It is estimated that the Company s total expenditures for capital, operating, maintenance and other costs to preserve and enhance environmental quality will be approximately $59.7 million during 2006 as compared to approximately $67.0 million in 2005. The Company continues to evaluate its environmental management systems to ensure compliance with existing and proposed environmental legislation and regulations and to better position itself in a competitive market.

OG&E

Air

On March 10, 2005, the Environmental Protection Agency (EPA) published the Clean Air Interstate Rule (CAIR). This rule is intended to control sulfur dioxide (SO2) and nitrogen oxide (NOX) emissions from utility boilers in order to minimize the interstate transport of air pollution. The state of Oklahoma is not listed as one of the states affected by the rule.

On March 25, 2005, the EPA issued the Clean Air Mercury Rule (CAMR) to limit mercury emissions from coal-fired boilers. The CAMR is currently subject to legal challenges. The CAMR requires reductions in mercury in two phases, phase I beginning in 2010 and phase II in 2018. The CAMR is based on the cap and trade program that will allow utilities to purchase mercury allowances (if available) rather than reduce emissions. It is anticipated that OG&E will need to obtain allowances or reduce its mercury emissions in Phase II by approximately 70 percent. The CAMR will also require continuous monitoring of mercury emissions from OG&E s coal-fired boilers beginning in 2009. The cost to OG&E of the CAMR has not yet been established because monitoring technology is still being developed. However, the cost to comply with the CAMR will be in addition to the cost of other emissions monitoring that is already in place pursuant to Title IV of the Clean Air Act Amendments of 1990.

On June 15, 2005, the EPA issued final amendments to its 1999 regional haze rule. These regulations are intended to protect visibility in national parks and wilderness areas (Class I areas) throughout the United States. In Oklahoma, the Wichita Mountains are the only area covered under the regulation. However, Oklahoma s impact on parks in other states must also be evaluated. Sulfates and nitrate aerosols (both emitted from coal-fired boilers) can lead to the degradation of visibility. The state of Oklahoma has joined with eight other central states and has begun to finalize the process of determining what, if any, impact emission sources in Oklahoma have on national parks and wilderness areas.

In September 2005, the Oklahoma Department of Environmental Quality (ODEQ) informally notified affected utilities that they would be required to perform a study to determine their impact on visibility in Class I areas. If an impact from affected OG&E facilities is determined, OG&E must propose emission controls to meet ODEQ requirements. Federal requirements are currently being incorporated into the state implementation plan through rulemaking. The study and proposed reductions or controls, if needed, must be submitted to the ODEQ by December 2006. OG&E will have five years from the date of approval of a compliance plan to institute any required reductions. If an impact is determined and the regulations remain in effect, then significant capital and operating expenditures will be required for OG&E s Sooner, Muskogee, Seminole and Horseshoe Lake generating stations.

In 1997, the EPA finalized revisions to the ambient ozone and fine particulate standards. After a court challenge, which delayed implementation, the EPA has now begun to finalize the implementation process. Based on the most recent monitoring data, the EPA has designated Oklahoma in attainment with both standards. However, on June 21 and 22, 2005, both Tulsa and Oklahoma City experienced high levels of ozone. If Tulsa and Oklahoma City continue to have elevated ozone levels for the next three ozone seasons, they could face redesignation to non-attainment status. To help avoid redesignation, both Tulsa and Oklahoma City have entered into an Early Action Compact with the EPA whereby voluntary measures will be enacted to reduce ozone.

On April 25, 2005, the EPA published a finding that all 50 states failed to submit the interstate pollution transport plans required by the Clean Air Act as a result of the adoption of the revised ambient ozone and fine particle standards. Failure to submit these implementation plans began a two-year timeframe, starting on May 25, 2005, during which states must submit a demonstration to the EPA that they do not affect air quality in downwind states. Earlier in 2005 it was unclear whether this could be accomplished by the state of Oklahoma and it was previously reported that there may be future significant expenditures required by OG&E if Oklahoma was determined to impact the air quality in downwind states. However, recent communications with the state of Oklahoma have affirmed they expect to be able to demonstrate no impact on other states and meet the May 25, 2007 deadline established by the EPA. Therefore, there should be no significant impact to OG&E as a result of the April 25, 2005 finding.

On December 21, 2005, the EPA proposed lowering the 24-hour fine particulate ambient standard while retaining the annual standard at its current level. In addition, the EPA proposed a new standard for inhalable coarse particulates. Based on past monitoring data, it appears that Oklahoma may be able to remain in attainment if the standards are finalized as proposed. However if parts of Oklahoma do become non-attainment , reductions in emissions from OG&E s coal-fired boilers could be required which may result in significant capital and operating expenditures.

The 1990 Clean Air Act includes an acid rain program to reduce SO2 emissions. Reductions were obtained through a program of emission (release) allowances issued by the EPA to power plants covered by the acid rain program. Each allowance is worth one ton of SO2 released from the smokestack. Plants may only release as much SO2 as they have allowances. Allowances may be banked and traded or sold nationwide. Beginning in 2000, OG&E became subject to more stringent SO2 emission requirements in Phase II of the acid rain program. These lower limits had no significant financial impact due to OG&E s earlier decision to burn low sulfur coal. In 2005, OG&E s SO2 emissions were well below the allowable limits.

The EPA allocated SO2 allowances to OG&E starting in 2000 and OG&E started banking allowances in 2001. In December 2005, OG&E sold 3,700 allowances for approximately $5.7 million. This transaction resulted in an increase in cash and a decrease in fuel clause under recoveries with no impact to earnings as the proceeds from these sales have been returned to OG&E s customers. In February 2006, OG&E sold 6,312 allowances for approximately $8.9 million. See Note 15 for a discussion of the SO2 allowance joint filing made in February 2006 which proposes how the proceeds from the sale of SO2 allowances should be accounted for in the future.

With respect to the NOX regulations of the acid rain program OG&E committed to meeting a 0.45 lbs/million British thermal unit (MMBtu) NOX emission level in 1997 on all coal-fired boilers. As a result, OG&E was eligible to exercise its option to extend the effective date of the lower emission requirements from the year 2000 until 2008. OG&E s

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average NOX emissions from its coal-fired boilers for 2005 were approximately 0.33 lbs/MMBtu. The regulations require that OG&E achieve a NOX emission level of 0.40 lbs/MMBtu for these boilers beginning in 2008. Further reductions in NOX emissions could be required if, among other things, legislation is enacted, a study currently being conducted by the state of Oklahoma determines that such NOX emissions are contributing to regional haze and that OG&E s facilities impact the air quality of the Tulsa or Oklahoma City metropolitan areas, or if Oklahoma becomes non-attainment with the fine particulate standard. Any of these scenarios would require significant capital and operating expenditures.

The ODEQ Clean Air Act Amendment Title V permitting program was approved by the EPA in March 1996. By March of 1997, OG&E had submitted all required permit applications. As of December 31, 2005, OG&E had received Title V permits for all of its generating stations. Since these permits require renewal every five years, OG&E has begun the renewal process for some of its generating stations. Air permit fees for generating stations were approximately $0.6 million in 2005. The fees for 2006 are estimated to be approximately the same as in 2005.

There have been a variety of unsuccessful legislative and litigation efforts to force mandatory control of utility emissions that allegedly contribute to climate change. If legislation is passed in the future requiring mandatory CO2 emission reductions to address climate change, this could have a tremendous impact on all coal-fired electric utilities, including OG&E s operations by requiring OG&E to significantly reduce the use of coal as a fuel source.

Waste

OG&E has sought and will continue to seek, new pollution prevention opportunities and to evaluate the effectiveness of its waste reduction, reuse and recycling efforts. In 2005, OG&E obtained refunds of approximately $1.0 million from its recycling efforts. 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.

Water

OG&E has one Oklahoma Pollutant Discharge Elimination System permit renewal pending. OG&E expects that this permit will be issued during the first quarter of 2006. OG&E expects that this permit, when finally issued, will continue to be reasonable in its requirements, allow operational flexibility and provide reductions in operating costs. Additionally, OG&E has filed an application with the state of Oklahoma for a new wastewater discharge permit for one of its facilities. OG&E expects that the wastewater discharge permit for this facility will be issued in the first or second quarters of 2006.

Section 316(b) of the Clean Water Act requires that the location, design, construction and capacity of any cooling water intake structure reflect the best available technology for minimizing environmental impacts. The EPA 316(b) rules for existing facilities became effective July 23, 2004. OG&E has engaged a consultant who has developed the required documentation for four OG&E facilities. These documents were submitted to the state agency on December 7, 2005 for review and approval. The Company has also provided the state of Oklahoma with information and requests that, if approved by the state, may reduce the impact of the 316(b) rules on the Company because if the Company s position is approved, three of the four Company facilities would not be required to comply with the 316(b) rules. Depending on the ultimate analysis and final determinations regarding the 316(b) rules, capital and/or operating costs may increase at any affected OG&E generating facility.

Enogex

The construction and operation of pipelines, plants and other facilities for transporting, processing, compressing or storing natural gas and other products may be subject to federal, state and local environmental laws and regulations, including those that can impose obligations to clean up hazardous substances at the locations at which Enogex operates. In most instances, the applicable regulatory requirements relate to water and air pollution control or solid waste management measures. Appropriate governmental authorities may enforce these laws and regulations with a variety of civil and criminal enforcement measures, including monetary penalties, assessment and remediation requirements and injunctions as to future compliance. Enogex generates some materials subject to the requirements of the Federal Resource Conservation and Recovery Act and the Clean Water Act and comparable state statutes, prepares and files reports and documents pursuant to the Toxic Substance Control Act and the Emergency Planning and Community Right to Know Act and obtains permits pursuant to the Federal Clean Air Act and comparable state air statutes.

Environmental regulation can increase the cost of planning, design, initial installation and operation of Enogex s facilities. Historically, Enogex s total expenditures for environmental control facilities and for remediation have not been

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significant in relation to its results of operations or financial condition. The Company believes, however, that it is reasonably likely that the trend in environmental legislation and regulations will continue to be towards stricter standards.

The Company has and will continue to evaluate the impact of its operations on the environment. As a result, contamination on Company property may be discovered from time to time.

Other

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

15. 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, short-term borrowing authorization and accounting practices are subject to the jurisdiction of the FERC. The Secretary of the Department of Energy has jurisdiction over some of OG&E s facilities and operations. For the year ended December 31, 2005 approximately 87 percent of OG&E s electric revenue was subject to the jurisdiction of the OCC, nine percent to the APSC and four percent to the FERC.

The OCC issued an order in 1996 authorizing OG&E to reorganize into a subsidiary of the Company. The order required that, among other things, (i) the Company permit the OCC access to the books and records of the Company and its affiliates relating to transactions with OG&E; (ii) the Company employ accounting and other procedures and controls to protect against subsidization of non-utility activities by OG&E s customers; and (iii) the Company 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 the Company 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 jurisdictional rates.

Completed Regulatory Matters

2002 Settlement Agreement

On November 22, 2002, the OCC signed a rate order containing the provisions of the Settlement Agreement in an OG&E rate case. The Settlement Agreement provided for, among other items: (i) a $25.0 million annual reduction in the electric rates of OG&E s Oklahoma customers which went into effect January 6, 2003; (ii) recovery by OG&E, through rate base, of the capital expenditures associated with the January 2002 ice storm; (iii) OG&E to acquire electric generation of not less than 400 MW (New Generation) to be integrated into OG&E s generation system; and (iv) recovery by OG&E, over three years, of the $5.4 million in deferred operating costs, associated with the January 2002 ice storm, through OG&E s rider for sales to other utilities and power marketers (off-system sales). Previously, OG&E had a 50/50 sharing mechanism in Oklahoma for any off-system sales. The Settlement Agreement provided that the first $1.8 million in annual net profits from OG&E s off-system sales will go to OG&E, the next $3.6 million in annual net profits from off-system sales will go to OG&E s Oklahoma customers and any net profits from off-system sales in excess of these amounts will be credited in each sales year with 80 percent to OG&E s Oklahoma customers and the remaining 20 percent to OG&E. During 2005, OG&E recovered approximately $1.8 million in annual net profits from off-system sales. Including this amount, OG&E has recovered a total of $5.4 million related to the regulatory asset since December 31, 2002, which is in accordance with the Settlement Agreement. During 2005, OG&E also credited as required approximately $3.6 million in annual net profits from off-system sales to OG&E s Oklahoma customers and the net profits from off-system sales that exceeded the $5.4 million were shared with 80 percent to OG&E s Oklahoma customers and the remaining 20 percent to OG&E. Beginning January 1, 2006, the annual net profits from off-system sales will be shared with 80 percent to OG&E s Oklahoma customers and 20 percent to OG&E.

OCC Order Confirming Savings

The Settlement Agreement required that, if OG&E did not acquire the New Generation by December 31, 2003, OG&E must credit $25.0 million annually (at a rate of 1/12 of $25.0 million per month for each month that the New Generation is not in place) to its Oklahoma customers beginning January 1, 2004 and continuing through December 31, 2006. As discussed in more detail below, in August 2003 OG&E signed an agreement to purchase a 77 percent interest in the McClain Plant, but due to a delay at the FERC, the acquisition was not completed by December 31, 2003. In the interim, OG&E entered into a power purchase agreement with the McClain Plant that delivered the savings guaranteed to OG&E s customers. OG&E requested that the OCC confirm that the steps it had taken, including the power purchase agreement, were satisfying the customer savings obligation under the Settlement Agreement and that OG&E would not be required to begin crediting its customers. On April 28, 2004, the OCC issued an order confirming that OG&E was delivering savings to its customers as required under the Settlement Agreement. The order removed any uncertainty over whether the OCC believed OG&E had to reduce its rates, effective January 1, 2004, while it awaited action by the FERC on its application to purchase the McClain Plant. A party to the OCC proceeding appealed the OCC s order to the Oklahoma Supreme Court. The appeal was denied and the OCC order is considered final.

Acquisition of Power Plant

On July 9, 2004, OG&E completed the acquisition of NRG McClain LLC s 77 percent interest in the 520 MW McClain Plant. This transaction was intended to satisfy the requirement in the Settlement Agreement to acquire New Generation. The McClain Plant, which includes natural gas-fired combined cycle combustion turbine units, is located near Newcastle, Oklahoma in McClain County, Oklahoma. The McClain Plant began operating in 2001. The owner of the remaining 23 percent interest in the McClain Plant is the Oklahoma Municipal Power Authority.

The closing of the purchase of the McClain Plant was subject to approval from the FERC. On July 2, 2004, the FERC authorized OG&E to acquire the McClain Plant. The FERC s approval was based on an offer of settlement in which OG&E proposed, among other things, to install certain new transmission facilities and to hire an independent market monitor to oversee OG&E s activity for a limited period. Two other parties, InterGen Services, Inc. and AES Shady Point (AES), opposed OG&E s offer of settlement and filed competing offers of settlement. In the July 2, 2004 order, the FERC: (i) approved OG&E s offer of settlement subject to conditions; (ii) rejected the competing offers of settlement; and (iii) approved OG&E s acquisition of the McClain Plant. As part of the July 2, 2004 order, OG&E agreed to undertake the following mitigation measures: (i) install certain transmission facilities designed to result in up to 600 MW of available transfer capability (ATC) from the Redbud Energy LP (Redbud) facility to the OG&E control area; (ii) pending completion of these transmission upgrades, provide up to 600 MW of ATC into OG&E s control area from the Redbud plant through changes to the dispatch of OG&E s generating units; and (iii) hire an independent market monitor to oversee OG&E s activity in its control area until the SPP implements a market monitor for the SPP regional transmission organization (RTO). OG&E completed the installation of the capital improvements and notified the FERC in writing on May 31, 2005 that these were completed. OG&E s obligation to redispatch its system to make 600 MW of ATC available to the Redbud power plant terminated upon completion of the transmission upgrades. The independent market monitor described above is designed to detect any anticompetitive conduct by OG&E from operation of its generation resources or its transmission system. The market monitoring function is performed daily and periodic reviews are also performed. To date, the independent market monitor has submitted six quarterly reports each covering the quarterly periods subsequent to the McClain Plant acquisition. Based on an analysis of transmission congestion data on OG&E s system, along with data on purchases and sales, generation dispatch data and power flows on OG&E s tie lines, the market monitor has concluded that OG&E has not acted in an anticompetitive manner through either dispatch of its generation or operation of its transmission system. Further, in the review of the disposition of requests for transmission service, the independent market monitor detected no improper behavior with regard to access to OG&E s transmission system. In August 2005, the market monitor initiated a special investigation into the circumstances surrounding the denial by the SPP of a request by Redbud for 440 MW in June 2005 of firm transmission service to OG&E. In its third quarter 2005 report, the market monitor concluded that differences in the SPP modeling assumptions and an error in modeling made by the SPP were the primary causes for the denial of service. The market monitor further stated that, if the FERC s July 2, 2004 order was based on the assumption that the McClain generating unit was not running to serve OG&E s load, the ATC created by the mitigation upgrades completed by OG&E in response to the FERC s order of July 2, 2004 matched the claims made by OG&E. On September 21, 2005, the FERC issued a letter requesting OG&E to provide information to confirm that the transmission facilities that OG&E constructed to mitigate the effects of the acquisition of the McClain interest resulted in 600 MW of ATC from Redbud to the OG&E control area. On October 3, 2005, OG&E responded that the facilities it constructed complied with the settlement the FERC approved regarding the acquisition of the McClain interest and resulted in the 600 MW of ATC. Redbud responded that, when it requested transmission service commencing in June 2005 after the facilities were completed, the SPP denied Redbud s request for service and, therefore, argued that the ATC was not created. OG&E explained that the SPP s denial of

76

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service to Redbud was due to an error by the SPP. Nonetheless, in October and November 2005, Redbud and OG&E filed additional pleadings addressing the ATC. On December 1, 2005, the FERC held a technical conference to address the issues regarding the ATC. On December 8, 2005, the FERC issued a notice requesting additional information regarding the ATC and asked parties to file initial post-conference comments on December 16, 2005 and reply comments on January 20, 2006. OG&E, Redbud, and the SPP filed comments on December 16, 2005. OG&E and Redbud filed reply comments on January 20, 2006. OG&E filed additional comments on February 6, 2006. While OG&E believes that no further action is warranted in this matter, it cannot predict what action the FERC ultimately could take.

OG&E expects the addition of the McClain Plant, including the effects of an interim power purchase agreement OG&E had with NRG McClain LLC while OG&E was awaiting regulatory approval to complete the acquisition, will provide savings, over a three-year period, in excess of $75.0 million to its Oklahoma customers. In the event OG&E is unable to demonstrate at least $75.0 million in savings to its customers during this 36-month period, OG&E will be required to credit its Oklahoma customers any unrealized savings below $75.0 million as determined at the end of the 36-month period ending December 31, 2006. At this time, OG&E believes that it will achieve at least $75.0 million in savings during this period.

Enogex FERC Section 311 2001 Rate Case

Pursuant to a settlement accepted by the FERC in May 2003 to resolve Enogex s 2001 Section 311 rate case, Enogex assessed a fee under certain market conditions for processing customer gas gathered behind processing plants so that it met the heating value standards of natural gas transmission pipelines (default processing fee). Pursuant to Enogex s Statement of Operating Conditions (SOC) that was effective through September 30, 2004, if Enogex s annual processing gross margin exceeded a specified threshold, Enogex was required to record a default processing fee refund obligation in an amount equal to the lesser of the default processing fees or the amount of the processing margin in excess of the specified threshold. In June 2004, Enogex billed default processing fees of approximately $0.2 million, which was recorded as deferred revenue. Based on the processing gross margin for 2004, these default processing fees billed to customers were recorded as deferred revenue and were refunded or credited to customers by April 30, 2005.

Enogex FERC Section 311 2004 Rate Case and related FERC dockets and 2006 Fuel Filing

On September 1, 2004, Enogex made a filing at the FERC to revise its previously approved SOC to permit, among other things, the unbundling, effective October 1, 2004, of its previously bundled gathering and transportation services. As a result, effective October 1, 2004, the FERC regulates Enogex s Section 311 transportation and any regulation of gathering is pursuant to Oklahoma statute.

On September 30, 2004, Enogex made its required triennial filing at the FERC to update its Section 311 maximum interruptible transportation rate. On September 29, 2004, Enogex filed an updated fuel factor with the FERC for the last quarter of 2004. Finally, on November 15, 2004, Enogex filed its annual updated fuel factor for fuel year 2005 (calendar year 2005).

Various parties intervened and protested the four filings but, after three technical conferences and various settlement discussions, reached a unanimous settlement that the FERC approved without modification or condition, by order of September 19, 2005. The Settlement established new maximum interruptible Section 311 zonal rates for an East Zone and a West Zone on the Enogex system, confirmed that Enogex could unbundle its gathering and transportation services and permitted the fuel factor percentages for the last quarter of 2004 and for fuel year 2005 to become effective, as filed. The FERC order concluded all four proceedings which resulted in no refunds being due. Because the FERC requires all intrastate pipeline offering 311 service to file a rate case every three years, Enogex must file its next rate case no later than October 1, 2007.

As required by the fuel tracker provisions of the SOC, Enogex made its annual fuel filing for the 2006 fuel year on November 15, 2005. As agreed in the Settlement, the fuel filing for the first time proposed an East Zone fuel percentage and a West Zone fuel percentage to be recalculated annually to replace the system-wide fuel percentage previously calculated annually for the whole Enogex system. Four parties moved to intervene. One party posed questions about the filing that Enogex answered on January 19, 2006. The FERC Staff later served data requests that Enogex answered on February 17, 2006. The FERC has not yet acted on the filing.

Gas Transportation and Storage Agreement

As part of the Settlement Agreement, OG&E also agreed to consider competitive bidding as a basis to select its provider for gas transportation service to its natural gas-fired generation facilities pursuant to the terms set forth in the Settlement Agreement. Because the required integrated service was not available in the marketplace from parties other than Enogex, OG&E advised the OCC that, after careful consideration, competitive bidding for gas transportation was rejected in favor of a new intrastate integrated, firm no-notice load following gas transportation and storage services agreement with Enogex. This seven-year agreement provides for gas transportation and storage services for each of OG&E s natural gas-fired generation facilities. OG&E will pay Enogex annual demand fees of approximately $46.8 million for the right to transport specified maximum daily quantities (MDQ) and maximum hourly quantities (MHQ) of gas at various minimum gas delivery pressures depending on the operational needs of the individual generating facility. In addition, OG&E supplies system fuel in-kind for its pro-rata share of actual fuel and lost and unaccounted for gas on the transportation system. To the extent OG&E transports gas in quantities in excess of the prescribed MDQ s or MHQ s, it pays an overrun service charge. During the years ended December 31, 2005, 2004 and 2003, OG&E paid Enogex approximately $47.6 million, $49.6 million and $44.7 million, respectively, for gas transportation and storage services.

On July 14, 2005, the OCC issued an order in this case approving a $41.9 million annual recovery. The OCC order disallowed the recovery by OG&E of the amount that Enogex charges OG&E for the cost of fuel used, or otherwise unaccounted for, in providing natural gas transportation and storage service to OG&E. Over the last three years, this amount has ranged from $1.2 million to $3.7 million annually. This amount was approximately $1.2 million in 2005 and is projected to be approximately $0.5 million in 2006. The OCC s order required OG&E to refund to its Oklahoma customers the difference between the amounts collected from such customers in the past based on an annual rate of $46.8 million for gas transportation and storage services and the $41.9 million annual rate authorized by the OCC s order. Based on the order, OG&E s refund obligation was approximately $8.8 million. OG&E began refunding this obligation in September 2005 through its automatic fuel adjustment clause. The balance of the refund obligation was approximately $6.0 million at December 31, 2005.

In connection with the Enogex gas transportation and storage agreement, OG&E has also recorded a refund obligation in Arkansas. OG&E expects to meet with the APSC in early 2006 to determine the amount of the refund. OG&E estimated its refund obligation to be approximately $1.1 million at December 31, 2005 to Arkansas customers assuming the Arkansas refund obligation is calculated consistent with the Oklahoma calculation.

Security Enhancements

On April 8, 2002, OG&E filed a joint application with the OCC requesting approval for security investments and a rider to recover these costs from the ratepayers. On August 14, 2002, OG&E filed testimony with the OCC outlining proposed expenditures and related actions for security enhancement and a proposed recovery rider. The OCC Staff retained a security expert to review the report filed by OG&E. On July 13, 2004, the security expert filed testimony that recommended: (i) $19.0 million in capital expenditures and $2.5 million annually in operating and maintenance expenses are justified to enhance the security of OG&E s infrastructure; and (ii) a security rider should be authorized to recover costs as these projects are completed. On August 4, 2004, OG&E filed responsive testimony that quantified the minimal customer impact and revised its request for security investments so that it was consistent with the OCC Staff s recommendations. On August 13, 2004, the only intervening party, the Oklahoma Industrial Energy Consumers (OIEC), filed a statement of position which supported the OCC Staff s recommendations. On October 28, 2004, all parties signed a joint stipulation that contains the OCC Staff s recommendations and authorizes up to a $5 million annual recovery from OG&E s customers for security enhancement. On December 21, 2004, the OCC issued an order approving the security rider. OG&E expects to implement the security rider by mid-year 2006.

Cogeneration Credit Rider

On September 17, 2004, OG&E filed an application and testimony with the OCC requesting a cogeneration credit rider. The requested rider would reduce charges to customers because of decreasing cogeneration payments made by OG&E beginning January 2005. The cogeneration credit rider is necessary because amounts currently recovered from customers in base rates include historically higher cogeneration payments. OG&E s cogeneration credit rider expired December 31, 2004. On October 29, 2004, the OCC Staff and other parties filed responsive testimony. Hearings in this case were held on November 15, 2004, at which time the administrative law judge recommended approval of the proposed cogeneration credit rider. On December 21, 2004, the OCC issued an order approving a new cogeneration credit rider which lowered electric bills by approximately $80 million in 2005. Any 2005 over/under recovery of the cogeneration credit rider is automatically included in the 2006 rider. In December 2005, the OCC order in OG&E s recently completed rate case authorized a new cogeneration credit rider effective January 2006. The 2006 cogeneration credit rider is approximately $78.7 million and the 2005 under recovery was approximately $3.7 million.

OG&E Oklahoma Rate Case Filing

On May 20, 2005, OG&E filed with the OCC an application for an annual rate increase of approximately $89.1 million to recover, among other things, its investment in, and the operating expenses of, the McClain Plant. The application also included, among other things, implementation of enhanced reliability programs in OG&E s system, increased fuel oil inventory, the establishment of a separate recovery mechanism for major storm expense, the establishment of new rate classes for public schools and related facilities, the establishment of a military base rider, the establishment of a new low income assistance tariff and the proposal to make the guaranteed flat bill pilot tariff permanent for residential and small business customers.

On September 12, 2005, several parties filed responsive testimony reflecting various positions on the issues related to this case. In particular, the testimony of the OCC Staff recommended that OG&E be entitled a rate increase of approximately $13.0 million, one-seventh the amount requested by OG&E in its May 20, 2005 application. The recommendations in the testimony of the Attorney General s office and the OIEC recommended a rate decrease of approximately $24 million and $31 million, respectively. Hearings in the rate case began on October 10, 2005 and concluded on October 24, 2005. On November 3, 2005, the Referee appointed by the OCC for this proceeding issued a report recommending an estimated rate increase of approximately $42 million for OG&E. On December 12, 2005, the OCC issued an order providing for a $42.3 million increase in rates and a 10.75 percent return on equity, based on a capital structure consisting of 55.7 percent equity and 44.3 percent debt. The new rates became effective in January 2006. Also included in the order, among other things, are new depreciation rates effective January 2006 and a provision which modified OG&E s mechanism for the recovery of over or under recovered fuel costs from its customers to allow interest to be applied to the over or under recovery.

As part of the rate order issued by the OCC in December 2005, OG&E received OCC approval for the creation of two new rate classes, Public Schools-Demand and Public Schools Non-Demand. These two classes of service will provide OG&E flexibility to provide targeted programs for load management to public schools and their unique usage patterns. Another item approved in the order was the creation of service level fuel differentiation which allows customers to pay fuel costs that better reflect energy losses on a service level basis. The OCC order also approved a military base rider which demonstrates Oklahoma s continued commitment to our military partners. OG&E s highly successful wind program was authorized to lower its cost on a per kwh basis, which provides subscribing customers the increased incentive to hedge against future natural gas prices. The order also enables OG&E s low-income qualified customers to receive relief on their summer electric bills by waiving the customer charge on their monthly bills from June to September of each year. Also included in OG&E s rate case application, but not approved, was the establishment of a separate recovery mechanism for major storm expense.

As provided in the 2002 Settlement Agreement, OG&E had the right to accrue a regulatory asset, for a period not to exceed 12 months subsequent to the completion of the acquisition and operation of the McClain Plant, consisting of the non-fuel operation and maintenance expenses, depreciation, cost of debt associated with the investment and ad valorem taxes. OG&E completed its acquisition of the McClain Plant on July 9, 2004. Accordingly, OG&E ceased accruing various operating and related costs associated with the McClain Plant as a regulatory asset on July 8, 2005. At December 31, 2005, the actual incurred expenses included in the McClain Plant regulatory asset were approximately $24.9

million. Such costs will be recovered over a four-year time period as authorized in the OCC rate order beginning in January 2006. The OCC authorized approximately $15.5 million of the $24.9 million regulatory asset to be included in OG&E s rate base for purposes of earning a return.

Pending Regulatory Matters

Review of OG&E s Fuel Adjustment Clause for Calendar Year 2003 and 2004

The OCC routinely audits activity in OG&E s fuel adjustment clause for each calendar year. On March 18, 2005, the OCC Staff filed Cause No. PUD 200500140 regarding Application of the Public Utility Division Director for Public Hearing to Review and Monitor OG&E s Fuel Adjustment Clause for Calendar Year 2003. On June 10, 2005, the OCC voted to combine this case with OG&E s recently completed rate case discussed above. On August 25, 2005, the OCC Staff filed Cause No. PUD 200500327 regarding Application of the Public Utility Division Director for Public Hearing to Review and Monitor OG&E s Fuel Adjustment Clause for Calendar Year 2004. On September 27, 2005, the OCC consolidated

these two proceedings into one proceeding. Intervenors in this proceeding include the OIEC, AES, Redbud and PowerSmith. Hearings in this proceeding are scheduled to begin May 11, 2006.

Competitive Bidding and Prudence Reviews for Electric Utility Providers

On March 10, 2005, the OCC filed Cause No. PUD 200500129 regarding Inquiry of the Oklahoma Corporation Commission into Guidelines for Establishing Rules for Competitive Bidding and Prudence Reviews for Electric Utility Providers. As an electric utility provider, any such guidelines that were adopted would likely impact OG&E. Technical conferences were held in April 2005, and a hearing and deliberations were held in early June. On June 10, 2005, the OCC voted to close this notice of inquiry and directed the OCC Staff to open a rulemaking to address the competitive bidding issue for electric utilities. A technical conference was held on October 28, 2005 and a hearing before the OCC began December 8, 2005. Rules were adopted by the OCC on January 18, 2006 and forwarded to the Governor for review and approval. If approved by the Governor, the rules will become effective immediately. OG&E does not expect these rules to have a significant impact on its operations.

Power Purchase Agreement Filings

On February 4, 2005, Chermac Energy Corporation (Chermac) and Sleeping Bear, LLC filed an application at the OCC (Cause No. PUD 200500059) seeking establishment of purchased power rates and a power purchase agreement with OG&E pursuant to PURPA for Chermac s proposed Buffalo/Sleeping Bear wind project. On April 28, 2005, Chermac and Sleeping Bear, LLC filed a second application at the OCC (Cause No. PUD 200500177) seeking establishment of purchased power rates and a power purchase agreement with OG&E pursuant to PURPA for Chermac s proposed Sleeping Bear South wind project. On September 15, 2005, the ALJ heard arguments on why the application should or should not be dismissed. On October 20, 2005, the ALJ suspended the current procedural schedule so that the parties involved in the proceeding could enter into negotiations. Subsequently, Chermac effectively designated Invenergy Wind LLC as its agent for settlement discussions. On December 22, 2005, the Company issued a press release announcing that OG&E had entered into a non-binding letter of intent to purchase a 120 MW wind farm planned for construction in northwestern Oklahoma. Invenergy Wind Development Oklahoma LLC (Invenergy LLC) would develop the new wind power-generation facility to be owned and operated by OG&E. The wind farm, north of Woodward in Harper County, is expected to cost approximately $195 million, including the cost of transmission interconnection facilities. A definitive Agreement To Engineer, Procure and Construct Wind Generation Energy System (EPC Contract) was reached on February 20, 2006, subject to various conditions. Those conditions include agreement by the parties as to certain exhibits to the EPC Contract, approval of the EPC Contract by the OG&E Board of Directors and approval of the EPC Contract by the Manager of Invenergy LLC, all of which have to be completed on or before March 13, 2006. In addition, 90 days subsequent to the occurrence of these events, OG&E or Invenergy LLC have the unilateral right to terminate the EPC Contract if certain additional events have not occurred, including the following: (i) OCC approval of the terms of the EPC Contract and of a recovery rider providing OG&E the opportunity to recover all costs associated with the wind facility, including transmission interconnection and transmission upgrade costs; (ii) completion by the SPP of all necessary transmission studies; (iii) Invenergy LLC s acquisition of certain land agreements; (iv) Invenergy LLC s execution of a contract acceptable to OG&E with a balance of work contractor; and (v) Invenergy LLC s acquisition of certain permits. If all of these conditions are met, the new wind farm is expected to be constructed and producing power on or before December 31, 2006. OCC hearings are expected to occur in April 2006.

OG&E Arkansas Rate Case Filing

Beginning in January 2006, OG&E began developing a rate case filing for the Arkansas jurisdiction. OG&E expects to make a rate case filing in Arkansas by mid-year 2006 requesting an increase in electric rates. The amount of the requested increase has not yet been determined.

OG&E SO2 Allowance Filing

On February 10, 2006, OG&E, the OCC Staff and AES filed a joint application with the OCC to determine the treatment of proceeds received from OG&E s sale of SO2 allowances and how these proceeds will be shared between OG&E and its customers. In the application, the parties propose that AES be held harmless from any reduction in OG&E s coal costs caused by the sale of SO2 allowances and that the proceeds of such sales are shared 80 percent to OG&E s Oklahoma customers and the remaining 20 percent to OG&E. A credit rider is being requested to pass the proceeds from the sale of the SO2 allowances to Oklahoma customers. Any proceeds from the sale of SO2 allowances in the Arkansas and the FERC jurisdictions will flow through OG&E s automatic fuel adjustment clause.

Southwest Power Pool

OG&E is a member of the SPP, the regional reliability organization for all or parts of Oklahoma, Arkansas, Kansas, Louisiana, New Mexico, Mississippi, Missouri and Texas. OG&E participated with the SPP in the development of regional transmission tariffs and executed a Membership Agreement with the SPP to facilitate interstate transmission operations within this region in 1998. In October 2003, the SPP filed an application with the FERC seeking authority to form an RTO. In a FERC order dated October 1, 2004, the SPP was granted RTO status, subject to the SPP submitting a further compliance filing. On January 25, 2005, the FERC issued an order on compliance filing stating that the November 1, 2004 SPP compliance filing satisfied the October 1 FERC order. The approval of the SPP RTO application is not expected to significantly impact the Company s consolidated financial results.

The regional state committee, which is comprised of commissioners of the applicable state regulatory commissions, finished its process of formulating a methodology for funding transmission expansion in the SPP control area by allocating costs of transmission expansion to the SPP members who benefit. The SPP Board of Directors adopted this plan and filed it with the FERC on February 28, 2005, Docket No. ER05-652. The FERC conditionally accepted the plan on April 21, 2005 with an effective date of May 5, 2005. The SPP made a second compliance filing on October 20, 2005 on various minor issues associated with the plan. On January 11, 2006, the FERC conditionally accepted the compliance filing, but required the SPP to make minor wording changes within 30 days. The SPP filed these minor wording changes on February 10, 2006.

The SPP filed on June 15, 2005, Docket No. ER05-1118, to create a real-time, offer-based imbalance energy market which will require cash settlements for over or under generation. Market participants, including OG&E, will be required to submit resource plans and can submit offer curves for each resource available for dispatch. In addition, the filing contains provisions allowing the SPP to order certain dispatching of generating units and a market monitoring plan which provides a clear set of rules, the potential consequences if the rules are violated and the areas in which an independent market monitor will examine and report. The scheduled implementation date of the imbalance energy market is May 1, 2006. On September 19, 2005, the FERC rejected the June 15, 2005 filing; however, the FERC provided guidance for the SPP s follow-up filing. On January 4, 2006, the SPP filed its follow-up filing in Docket No. ER06-451 by submitting tariff revisions to incorporate imbalance energy market and market monitoring procedures.

On August 8, 2005, the SPP filed with the FERC for approval, Docket No. ER05-1285, which contained, among other items, a standard definition of transmission to be used in the SPP RTO. The definition provides a uniform basis for application of formula rates, exercise of functional control of the transmission system, planning and expansion of the transmission system, compensation of new transmission owners and provides for a three-year period for petitioning for deviations from the bright line definition. The basic definition of transmission facilities is similar to definitions accepted for other RTO s. On September 30, 2005, the FERC accepted the definition, with minor modification. On November 29, 2005, the SPP submitted a compliance filing consistent with the September 30 FERC directions for modification.

On August 5, 2004, OG&E filed with the APSC in Docket 04-111-U an application for approval of its participation in the SPP RTO. The application was filed pursuant to the provisions of Arkansas code which requires that no public utility shall sell, lease, rent or otherwise transfer, in any manner, control of electric transmission facilities in this state without the approval of the APSC, provided that the approval is required only to the extent the transaction is not subject to the exclusive jurisdiction of the FERC or any other federal agency. On October 12, 2004, the SPP filed with the APSC in Docket 04-137-U an application for a Certificate of Public Convenience and Necessity for the limited purpose of managing and coordinating the use of certain transmission facilities located within the state of Arkansas. The APSC has consolidated these two dockets, among others, and a public hearing is scheduled for April 4, 2006.

Market-Based Rate Authority

On December 22, 2003, OG&E and OERI filed a triennial market power update based on the supply margin assessment test. On April 14, 2004, the FERC issued: (1) interim requirements for the FERC jurisdictional electric utilities who have been granted authority to make wholesale sales at market-based rates; and (2) an order initiating a new rulemaking on future market-based rates authorizations. The interim method for analyzing generation market power requires two assessments whether the utility is a pivotal supplier based on a control area s annual peak demand and whether the utility exceeds certain market share thresholds on a seasonal basis. If an applicant fails to pass either assessment, the FERC will presume that the utility can exercise generation market power and will initiate an investigation into the scope of the applicant s market power. The FERC will allow a utility to rebut that presumption through the submission of additional information. If an applicant is found to have generation market power, the applicant must propose a market power mitigation plan. The new interim assessment methods are applicable to all pending initial market-based rate applications and triennial reviews pending the rulemaking described below. On May 13, 2004, the FERC directed all utilities with pending three year

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market-based reviews to revise the generation market power portion of their three year review to address the two interim tests described above. In the rulemaking proceeding, the FERC is seeking comments on the adequacy of the FERC s current analysis of market-based rate filings, including the adequacy of the new interim assessment of generation market power. OG&E and OERI submitted a compliance filing to the FERC on February 7, 2005 which shows the impact of the new requirements on OG&E and OERI. In the compliance filing, OG&E and OERI passed the pivotal supplier screen but failed to pass the market share screen. OG&E and OERI provided an explanation as to why its failure of the market share screen should not be viewed as an indication that they can exercise generation market power. One party, Redbud, protested the OG&E and OERI filing and proposed that the FERC require OG&E to adopt an economic dispatch program as a means to mitigate OG&E s and OERI s generation market power. On March 15, 2005, OG&E and OERI responded to Redbud s protest. In that response OG&E and OERI reiterated that the information they initially filed demonstrates that they cannot exercise market power and that Redbud s proposal is beyond the scope of the proceeding. Another party, AES, has requested intervention in this case in protest. In June 2005, the FERC granted the Redbud and AES interventions.

On June 7, 2005, the FERC issued an order on OG&E s and OERI s market-based rate filing. Because OG&E and OERI failed the market share screen for OG&E s control area, the FERC set OG&E s and OERI s market-based sales in OG&E s control area for investigation pursuant to Section 206 of the Federal Power Act to investigate whether OG&E and OERI may continue to sell power at market-based rates in OG&E s control area. The initiation of the investigation and imposition of the filing requirements do not constitute a finding that OG&E and OERI can exercise market power. OG&E and OERI have been requested to provide additional information that demonstrates to the FERC that they cannot exercise market power in the first-tier markets as well. However, the order conditionally allows OG&E and OERI to sell power in first-tier markets subject to OG&E and OERI providing additional information that clearly shows that they pass the market share screen for the first-tier markets. OG&E and OERI provided that additional information on July 7, 2005. On August 8, 2005, OG&E and OERI informed the FERC that they will: (i) adopt the FERC default rate mechanism for sales of one week or less that are delivered to customers in OG&E s control area; and (ii) commit not to enter into any sales with a duration of between one week and one year to loads that are delivered to customers in OG&E s control area. OG&E and OERI also informed the FERC that any new agreements for long-term sales to loads that are delivered to customers in OG&E s control area will be filed with the FERC under Section 205 and not under market based rate tariffs. Interventions and comments on OG&E s and OERI s August 8, 2005 filing were due December 22, 2005. No party filed comments. On January 20, 2006, the FERC issued a Notice of Institution of Proceeding and Refund Effective Date for the purpose of establishing the date from which any subsequent market-based sales would be subject to refund in the event the FERC concludes after investigation that OG&E possesses market power. The refund effective date is March 27, 2006. OG&E and OERI do not know when the FERC will conclude this investigation or act on the August 8, 2005 filing.

Department of Energy Blackout Report

On April 5, 2004, the U.S. Department of Energy issued its final report regarding the August 14, 2003 electric blackout in the eastern United States, which did not have an adverse affect on OG&E s electric system. The report recommends a number of specific changes to current statutes, rules or practices in order to improve the reliability of the infrastructure used to transmit electric power. The recommendations include the establishment of mandatory reliability standards and financial penalties for noncompliance. On April 14, 2004, the FERC issued a policy statement requiring electric utilities, including OG&E, to submit a report on vegetation management practices and indicating the FERC s intent to make North American Electric Reliability Council reliability standards mandatory. On June 17, 2004, OG&E filed its report on vegetation management practices with the FERC. During 2004, OG&E spent less than $0.2 million related to the implementation of blackout report recommendations. Implementation of the blackout report recommendations and the FERC policy statement could increase future transmission costs, but the extent of the increased costs is not known at this time.

National Energy Legislation

In August 2005, Congress passed and the President signed into law a comprehensive energy bill, portions of which are of interest to the Company and to the industry. There are several provisions in the bill that have a positive impact on the Company. Provisions minimizing the risk of future uneconomic purchased power contracts forced on the Company under PURPA, tax incentives for investment in electric transmission and gas pipeline systems, mandatory reliability requirements by the North American Electric Reliability Council with oversight by the FERC and improved FERC siting authority for construction of electric transmission in disputed areas are included in the new law. Another significant provision for the utility industry is the repeal of the Public Utility Holding Company Act of 1935. This provision has minimal impact on the current operations of the Company. The FERC is in the process of developing regulations and policies mandated by the new energy act, some of which could have significance for electric utilities such as OG&E. In particular, OG&E will closely monitor the FERC s implementation of the new statute s conditional elimination of utilities obligation to purchase power from cogenerators. Similarly, OG&E will closely monitor the FERC and U.S. Department of Energy proceedings with

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regard to rules on the new mandatory reliability regime governing all electric generators, new transmission incentives and the concept of economic or efficient dispatch.

State Legislative Initiatives

Oklahoma

As previously reported, the Oklahoma legislature originally adopted the Electric Restructuring Act of 1997 (the 1997 Act) to provide retail customers in Oklahoma with a choice of their electric supplier. The scheduled start date for customer choice has been indefinitely postponed. In the 2003 legislative session, attempts to repeal the 1997 Act were initiated, but the session ended without repeal of the 1997 Act. It is unknown at this time whether the 1997 Act will be repealed.

In the 2005 legislative session, House Bills 1910 and 1386 were introduced that may have an impact on the Company. House Bill 1910 which proposed that electric utilities: (i) be granted the certainty of knowing that costs of transmission upgrades assigned by an RTO will be recoverable, (ii) be granted the certainty of knowing that costs for a pre-approved plan to handle state and federally mandated environmental upgrades will be recoverable; and (iii) be able to seek pre-approval for generation construction projects, passed the legislature and was signed into law on May 11, 2005, at which time it became effective. House Bill 1386 proposed that utilities be able to continue to serve and expand, if so desired, in service territories in which they currently serve but which a municipality annexes. Currently, there is some legal uncertainty as to whether utilities can expand in an area described above. House Bill 1386 would have removed that uncertainty, but the bill failed to be heard for a final vote in the Senate and it carried over in its current form in the legislative session which began February 2006.

Arkansas

In April 1999, Arkansas passed a law (the Restructuring Law) calling for restructuring of the electric utility industry at the retail level. The Restructuring Law, which had initially targeted customer choice of electricity providers by January 1, 2002, was repealed in March 2003 before it was implemented. As part of the repeal legislation, electric public utilities were permitted to recover transition costs. OG&E incurred approximately $2.4 million in transition costs necessary to carry out its responsibilities associated with efforts to implement retail open access. On January 20, 2004, the APSC issued an order which authorized OG&E to recover approximately $1.9 million in transition costs over an 18-month period beginning February 2004. During the third quarter of 2005, OG&E recovered all of these costs.

As discussed above, legislation was enacted in Oklahoma and Arkansas that was to restructure the electric utility industry in those states. The Arkansas legislation was repealed and implementation of the Oklahoma restructuring legislation has been delayed and seems unlikely to proceed during the near future. Yet, if and when implemented, this legislation could deregulate OG&E s electric generation assets and cause OG&E to discontinue the use of SFAS No. 71 with respect to its related regulatory balances. The previously enacted Oklahoma and Arkansas legislation would not affect OG&E s electric transmission and distribution assets and OG&E believes that the continued use of SFAS No. 71 with respect to the related regulatory balances is appropriate. Based on a current evaluation of the various factors and conditions that are expected to impact future cost recovery, management believes that its regulatory assets, including those related to generation, are probable of future recovery.

Summary

The Energy Act, the actions of the FERC, the restructuring legislation in Oklahoma and other factors are intended to increase competition in the electric industry. OG&E has taken steps in the past and intends to take appropriate steps in the future to remain a competitive supplier of electricity. While OG&E is supportive of competition, it believes that all electric suppliers must be required to compete on a fair and equitable basis and OG&E is advocating this position vigorously.

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16. Fair Value of Financial Instruments

The following information is provided regarding the estimated fair value of the Company s financial instruments, including derivative contracts related to the Company s price risk management activities, as of December 31:

	2005		2004	
	Carrying	**Fair**	Carrying	Fair
(In millions)	**Amount**	**Value**	Amount	Value
Price Risk Management Assets				
Energy Trading Contracts	**$ 125.4**	**$ 125.4**	$ 62.8	$ 62.8
Interest Rate Swaps	**0.1**	**0.1**	7.9	7.9
Price Risk Management Liabilities				
Energy Trading Contracts	**$ 120.1**	**$ 120.1**	$ 42.2	$ 42.2
Interest Rate Swaps	**0.1**	**0.1**	---	---
Long-Term Debt				
Senior Notes	**$ 587.8**	**$ 612.2**	$ 810.9	$ 864.1
Industrial Authority Bonds	**135.4**	**135.4**	135.4	135.4
Enogex Notes continuing operations	**407.6**	**441.2**	447.1	482.1
Enogex Notes discontinued operations	**---**	**---**	67.0	71.0
Other	**220.0**	**220.0**	---	---

The carrying value of the financial instruments on the Consolidated Balance Sheets not otherwise discussed above approximates fair value except for long-term debt which is valued at the carrying amount. The valuation of the Company s interest rate swaps and energy trading contracts was determined primarily 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 and the potential impact of liquidating the position in an orderly manner over a reasonable period of time. The fair value of the Company s long-term debt is based on quoted market prices and management s estimate of current rates available for similar issues with similar maturities.

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, 2005 and 2004, and the related consolidated statements of income, retained earnings, comprehensive income and cash flows for each of the three years in the period ended December 31, 2005. Our audits also included the financial statement schedule listed in the Index at Item 15. These financial statements and schedule are the responsibility of the Company s management. Our responsibility is to express an opinion on these financial statements and schedule 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, 2005 and 2004, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2005, in conformity with U.S. generally accepted accounting principles. Also, in our opinion, the related financial statement schedule, when considered in relation to the basic financial statements taken as a whole, presents fairly, in all material respects, the information set forth herein.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of OGE Energy Corp. s internal control over financial reporting as of December 31, 2005, 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 21, 2006 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP
Ernst & Young LLP

Oklahoma City, Oklahoma

February 21, 2006

85

Supplementary Data

Interim Consolidated Financial Information (Unaudited)

In the opinion of the Company, the following quarterly information includes all adjustments, consisting of normal recurring adjustments, necessary to fairly present the Company s consolidated results of operations for such periods:

Quarter ended (*In millions, except per share data)*		Dec 31	Sep 30	Jun 30	Mar 31
Operating revenues (A)(B)	**2005**	**$ 1,653.1**	**$ 1,681.5**	**$ 1,339.1**	**$ 1,274.5**
	2004	1,397.8	1,319.3	1,150.5	1,036.8
Operating income (A)(B)	**2005**	**$ 40.4**	**$ 190.1**	**$ 77.0**	**$ 23.0**
	2004	34.6	161.1	80.3	27.8
Net income (loss)(B)	**2005**	**$ 56.1**	**$ 111.1**	**$ 38.5**	**$ 5.3**
	2004	9.7	94.6	39.0	10.2
Basic earnings per average common share	**2005**	**$ 0.62**	**$ 1.23**	**$ 0.43**	**$ 0.06**
	2004	0.10	1.08	0.44	0.12
Diluted earnings per average common share	**2005**	**$ 0.62**	**$ 1.22**	**$ 0.42**	**$ 0.06**
	2004	0.10	1.07	0.44	0.12

(A) These amounts have been restated due to the sales of EAPC and Enerven being reported as discontinued operations during 2005 and 2004.

(B) In January 2005, a cogeneration credit rider was implemented at OG&E as part of the Oklahoma retail customer electric rates in order to return purchase power capacity payment reductions and any change in operating and maintenance expense related to cogeneration previously included in base rates to OG&E s customers. This rider resulted in the seasonal over or under collection of revenues as the rider is based on an equal monthly amount kwh usage as compared to actual kwh usage. Due to the seasonal rates of OG&E s electric sales, this resulted in a temporary over collection of operating revenues in excess of the reduction in operating and maintenance expense for the first and second quarters of 2005 of approximately $5.9 million ($3.6 million after tax or $0.04 per share) and a temporary under collection of operating revenues in excess of the reduction in operating and maintenance expense for the third quarter of 2005 of approximately $10.0 million ($6.1 million after tax or $0.07 per share). In August 2005, OG&E determined that its net income should not be affected by over or under collections on a temporary or permanent basis, and accordingly, any difference should be deferred as a regulatory asset or liability. As a result, in order to better reflect the purchase power capacity payment reductions and any change in operating and maintenance expense related to cogeneration from January 1, 2005 to September 30, 2005, OG&E recorded a regulatory asset of approximately $4.1 million in current assets as Prepayments and Other in the Consolidated Balance Sheet and a corresponding $4.1 million increase to Operating Revenues in the Consolidated Statement of Income. Going forward, OG&E expects any over or under collections related to the cogeneration credit rider to be reflected as a regulatory asset or liability. The balance of the cogeneration credit rider under recovery was approximately $3.7 million at December 31, 2005. Any 2005 over/under recovery of the cogeneration credit rider is automatically included in the 2006 rider. In December 2005, the OCC order in OG&E s recently completed rate case authorized a new cogeneration credit rider effective January 2006. The 2006 cogeneration credit rider is approximately $78.7 million and the 2005 under recovery was approximately $3.7 million.

Dividends

COMMON STOCK
Common quarterly dividends paid (as declared) in 2005, 2004, and 2003 were $0.33 ¼.

Present rate $0.33 ¼

Payable 30th of January, April, July, and October

86

Security Ratings*

	Moody s	Standard & Poor s	Fitch s
OG&E Senior Notes	A2	BBB+	AA-
Enogex Notes	Baa3	BBB+	BBB
OGE Energy Corp. Senior Notes	Baa1	BBB	A
OGE Energy Corp. Commercial Paper	P2	A2	F1

* The ratings of Moody s, Standard & Poor s and Fitch s reflect only the views of such organizations and each rating should be evaluated independently of the other. The ratings are not recommendations to buy, sell or hold securities. Such ratings may be subject to revision or withdrawal at any time by the credit rating agency. Moody s, Standard & Poor s and Fitch s currently maintain a stable outlook on its rating of the OG&E Senior Notes, Enogex Notes and OGE Energy Corp. commercial paper.

For further information regarding these ratings, please contact the Treasurer of the Company at 321 North Harvey, P.O. Box 321, Oklahoma City, Oklahoma 73101-0321, (405) 553-3800.

Market Prices

	2005		2004	
NEW YORK STOCK EXCHANGE	**High**	**Low**	High	Low
Common				
First Quarter	**$ 27.59**	**$ 25.15**	$ 26.70	$ 23.03
Second Quarter	**29.22**	**26.11**	26.80	22.85
Third Quarter	**30.60**	**27.74**	26.48	24.10
Fourth Quarter	**28.60**	**24.41**	26.95	25.17

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. 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 (CEO) and Chief Financial Officer (CFO), of the effectiveness of the Company s disclosure controls and procedures, the CEO and CFO 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).

The Company has filed the Section 302 CEO and CFO certifications as exhibits to its 2005 Form 10-K. The Company has also filed the 2005 Section 303A.12(a) CEO certification to the New York Stock Exchange on June 3, 2005.

Management s Report on Internal Control Over Financial Reporting

The management of OGE Energy Corp. (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, 2005. 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, 2005, 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 management s assessment of the Company s internal control over financial reporting. This report appears on the following page.

/s/ Steven E. Moore Steven E. Moore, Chairman of the Board, President and Chief Executive Officer	/s/ Peter B. Delaney Peter B. Delaney, Executive Vice President and Chief Operating Officer

/s/ James R. Hatfield
James R. Hatfield, Senior Vice President and Chief Financial Officer

/s/ Scott Forbes
Scott Forbes, Controller and Chief Accounting Officer

88

REPORT OF INDEPENDENT REGISTERED PUBLIC

ACCOUNTING FIRM

The Board of Directors and Stockholders

OGE Energy Corp.

We have audited management s assessment, included in the accompanying Management s Report on Internal Control Over Financial Reporting, that OGE Energy Corp. maintained effective internal control over financial reporting as of December 31, 2005, 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. Our responsibility is to express an opinion on management s assessment and an opinion on the effectiveness of 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, evaluating management s assessment, testing and evaluating the design and operating effectiveness of internal control, 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, management s assessment that OGE Energy Corp. maintained effective internal control over financial reporting as of December 31, 2005, is fairly stated, in all material respects, based on the COSO criteria. Also, in our opinion, OGE Energy Corp. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2005, 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, 2005 and 2004, and the related consolidated statements of income, retained earnings, comprehensive income and cash flows for each of the three years in the period ended December 31, 2005 of OGE Energy Corp. and our report dated February 21, 2006 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP
Ernst & Young LLP

Oklahoma City, Oklahoma

February 21, 2006

P.O. Box 321

Oklahoma City, Oklahoma

73101-0321

(405) 553-3000

The Board recommends a vote FOR the election as directors of the nominees named below and FOR ratification of the appointment of Ernst & Young LLP as the Company s principal independent accountants.

Please mark your votes as indicated in this example X

	FOR all nominees (list exceptions below)	WITHHOLD AUTHORITY to vote for all nominees
1. Election of Directors		
NOMINEES: 01 John D. Groendyke, 02 Robert O. Lorenz, 03 Steven E. Moore	______	______

Instructions: To withhold authority to vote for any individual nominee, write that nominee's name on the line above.

	FOR	AGAINST	ABSTAIN
2. Ratify the appointment of Ernst & Young LLP as our principal independent accountants.	______	______	______

3. In their discretion, the proxies are authorized to vote upon such other business as may properly come before the meeting.

Choose **MLink**^{SM} for Fast, easy and secure 24/7 online access to your future proxy materials, investment plan statements, tax documents and more. Simply log on to **Investor ServiceDirect**^{R} at www.melloninvestor.com/isd where step-by-step instructions will prompt you through enrollment.

Discontinue mailing of duplicate Annual Report. ______ I will attend the Annual Meeting. ______

PLEASE DATE AND SIGN EXACTLY AS NAME APPEARS. EACH JOINT OWNER SHOULD SIGN. ATTORNEY, EXECUTOR, ADMINISTRATOR, TRUSTEE OR OTHERS SIGNING IN A REPRESENTATIVE CAPACITY SHOULD GIVE THEIR FULL TITLES.

X ______________________ / / 2006 X ______________________ / / 2006

Signature of Shareowner Date Signature of Shareowner Date

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Vote by Internet or Telephone or Mail
24 Hours a Day, 7 Days a Week

Internet and telephone voting is available through 11:59 PM Eastern Time
the day prior to annual meeting day.

Your Internet or telephone vote authorizes the named proxies to vote your shares in the same manner as if you marked, signed and returned your proxy card.

Internet		**Telephone**		**Mail**
http://www.proxyvoting.com/oge		**1-866-540-5760**		Mark, sign and date your proxy card and return it in the enclosed postage-paid envelope.
Use the internet to vote your proxy. Have your proxy card in hand when you access the web site.	OR	Use any touch-tone telephone to vote your proxy. Have your proxy card in hand when you call.	OR	

If you vote your proxy by Internet or by telephone, you do NOT need to mail back your proxy card.

You can view the Annual Report and Proxy Statement on the internet at http://www.oge.com

OGE ENERGY CORP.
Annual Meeting of Shareowners
May 18, 2006

The undersigned hereby appoints Steven E. Moore, H. H. Champlin, and Robert Kelley, and each of them severally, with full power of substitution and with full power to act with or without the other, as the proxies of the undersigned to represent and to vote all shares of stock of OGE Energy Corp. held of record by the undersigned on March 21, 2006, at the Company s Annual Meeting of Shareowners to be held on May 18, 2006, and at all adjournments thereof, on all matters coming before said meeting.

THIS PROXY, WHICH IS SOLICITED BY THE BOARD OF DIRECTORS, WILL BE VOTED AS DIRECTED. IF NO DIRECTION IS MADE, THE PROXY WILL BE VOTED FOR THE ELECTION AS DIRECTORS OF THE NOMINEES NAMED ON THE REVERSE SIDE OF THIS PROXY CARD AND FOR THE RATIFICATION OF THE APPOINTMENT OF ERNST & YOUNG LLP AS THE COMPANY S PRINCIPAL INDEPENDENT ACCOUNTANTS.

PLEASE VOTE BY INTERNET, TELEPHONE, OR MARK, DATE, SIGN AND RETURN THIS PROXY CARD PROMPTLY USING THE ENCLOSED ENVELOPE. Unless you attend and vote in person, you MUST vote by Internet, telephone, or sign and return your proxy in order to have your shares voted at the meeting.

(Continued on reverse side)

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321 North Harvey Avenue
Oklahoma City, Oklahoma 73102

Admission Ticket

RETAIN FOR ADMITTANCE

Annual Meeting of

OGE Energy Corp. Shareowners

Thursday, May 18, 2006 10:00 a.m.
National Cowboy and Western Heritage Museum
1700 Northeast 63rd Street
Oklahoma City, Oklahoma

LOCATION OF THE NATIONAL COWBOY AND WESTERN HERITAGE MUSEUM

East Bound or West Bound I-44

Exit to Martin Luther King Ave., continuing north approximately .2 miles. Proceed west on Northeast 63rd Street .5 miles to National Cowboy and Western Heritage Museum.

It is important that your shares are represented at this meeting, whether or not you attend the meeting in person. To make sure your shares are represented, we urge you to vote by Internet, telephone, or complete and mail the proxy card above.