OGE ENERGY CORP
Form DEF 14A
March 30, 2007

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

[ ] Soliciting Material Pursuant to Rule 14a-11(c) or Rule 14a-12

OGE ENERGY CORP.

(Name of Registrant as Specified In Its Charter)

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

Payment of Filing Fee (Check the appropriate box):

[X] No fee required

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1) Title of each class of securities to which transaction applies:

2) Aggregate number of securities to which transaction applies:

3) Per unit price or other underlying value of transaction computed pursuant to Exchange Act Rule 0-11 (Set forth the amount on which the filing fee is calculated and state how it was determined):

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1) Amount Previously Paid:

2) Form, Schedule or Registration Statement No.:

3) Filing Party:

4) Date Filed:

Contents

Notice of Annual Meeting of Shareowners
and Proxy Statement

Thursday, May 17, 2007, at 10:00 a.m.

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

March 30, 2007

Dear Shareowner:

You are cordially invited to attend the annual meeting of OGE Energy Corp. at 10:00 a.m. on Thursday, May 17, 2007, 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
and Chief Executive Officer

(ii)

Notice of Annual Meeting

of Shareowners

The Annual Meeting of Shareowners of OGE Energy Corp. will be held on Thursday, May 17, 2007, 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 four 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 34 will assist you in locating the National Cowboy and Western Heritage Museum.

Shareowners who owned stock on March 20, 2007, 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 30, 2007

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.

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Proxy Statement

March 30, 2007

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 17, 2007, at 10:00 a.m. For the convenience of those shareowners who may attend the meeting, a map is printed on page 34 that gives directions to the National Cowboy and Western Heritage Museum. At the meeting, we intend to present the first two items in the accompanying notice 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 four 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 20, 2007, you are entitled to one vote per share upon each matter presented at the meeting.

On March 1, 2007, there were 91,568,663 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 30, 2007. 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 30, 2007, to all of our shareowners who owned stock on March 20, 2007.

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 four persons are the nominees of the Board to be elected for such three-year term at the Annual Meeting to be held on May 17, 2007: Mr. Luke R. Corbett, Mr. Peter B. Delaney, Mr. Robert Kelley and Mr. J.D. Williams. 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 these individuals, as well as each other director of the Company during 2006, also was a director of the Company s principal subsidiary, Oklahoma Gas and Electric Company (OG&E).

The enclosed proxy, unless otherwise specified, will be voted in favor of the election as directors of the previously listed four 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 1.2% 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, 2007, concerning the four nominees for directors, as well as the directors whose terms of office e

Nominees for Election for Term Expiring at 2010 Annual Meeting of Shareowners

LUKE R. CORBETT, 60, is the former Chairman and Chief Executive Officer of Kerr-McGee Corporation, which engageded in oil and gas exploration a

PETER B. DELANEY, 53, is President and Chief Operating Officer of the Company and OG&E. From 2004 to January 2007, he was Executive Vice Pre

ROBERT KELLEY, 61, is President of Kellco Investments Inc., a private investment company. Prior to May 1, 2001, he served as Chairman of the Boarc

J. D. WILLIAMS, 69, 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 f

Directors Whose Terms Expire at 2009 Annual Meeting of Shareowners

JOHN D. GROENDYKE, 62, is Chairman of the Board and Chief Executive Officer of Groendyke Transport Incorporated, a bulk truck transportation co

ROBERT O. LORENZ, 60, is a retired partner of the Arthur Andersen accounting firm. Mr. Lorenz joined Arthur Andersen in 1969, became a partner in

STEVEN E. MOORE, 61, is Chairman and Chief Executive Officer of the Company and of OG&E, having been appointed to such positions with the Con

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Directors Whose Terms Expire at 2008 Annual Meeting of Shareowners

HERBERT H. CHAMPLIN, 69, is President of Champlin Exploration, Inc., an independent oil producer, and Chairman of Enid Data Systems, computer

LINDA PETREE LAMBERT, 67, is President of LASSO Corporation, a diversified oil and gas investment company, and President of Enertree, L.L.C., a

RONALD H. WHITE, M.D., 70, is a practicing cardiologist and President, Partner and Director of Oklahoma Cardiovascular Associates, and a member o

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 four nominees as director. Withholding authority is treated as a vote against.

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

INFORMATION CONCERNING THE BOARD OF DIRECTORS

General. Each member of our Board of Directors other than Mr. Delaney was also a director of OG&E during 2006. The Board of Directors of the Company met on ten occasions during 2006 and the Board of Directors of OG&E met on seven occasions during 2006. Each director attended at least 85% 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.

The members of the committees during 2006, the general functions of the committees and number of committee meetings in 2006 are set forth below.

Name of Committee and Members	**General Functions of the Committee**	**Number of Meetings in 2006**
Compensation Committee: Herbert H. Champlin Luke R. Corbett* John D. Groendyke Robert Kelley Ronald H. White, M.D. J. D. Williams	Oversees compensation of directors and principal officers executive compensation policy benefit programs	6
Audit Committee: Herbert H. Champlin Luke R. Corbett Robert Kelley* Linda Petree Lambert 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	4

Nominating and Corporate Governance Committee: John D. Groendyke	Reviews and recommends	5
Linda Petree Lambert	nominees for election as directors	
Robert O. Lorenz	membership of director committees	
Ronald H. White, M.D.	succession plans	
J. D. Williams*	various corporate governance issues	

* Chairperson

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Corporate Governance

Corporate Governance Guidelines. 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 (CEO) and the president should be the only Company executives 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 CEO and the president, 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 CEO 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 for 2006.

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, which include all non-management directors, are to meet in executive session, generally coinciding with regularly scheduled Board meetings. In 2006, the independent directors met in executive session nine 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 CEO 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 currently has ten directors, eight of whom are independent within the meaning of the New York Stock Exchange listing standards. Our Chairman and CEO and our President are the only directors who are not considered independent. 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;

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 judgment as a director.

For purposes of determining whether the directors met the aforementioned tests and should be deemed independent, the Board concluded that the purchase of electricity from OG&E at rates approved by a state utility commission does not constitute a material relationship. Based on this, the Board determined that each of the following members of the Board met the aforementioned independence standards: Herbert H. Champlin; Luke R. Corbett; 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 CEO and an employee of the Company. Mr. Delaney does not meet the aforementioned independence standards because he is the current President and Chief Operating Officer (COO) and an employee of the Company.

Standing Committees. The standing committees of the Board of Directors include - 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. Each of these committee charters is available on our website at *www.oge.com* under the heading Investors, Corporate Governance. The duties and responsibilities of the Board committees are reviewed regularly and are outlined above.

Audit Committee Financial Expert. The Board has determined that Mr. Robert Kelley meets the Securities and Exchange Commission definition of audit committee financial expert.

Process Related to Executive Officer and Director Compensation. Under the terms of its charter, the compensation committee of the Board of Directors (the Compensation Committee) has broad authority to develop and implement the Company s compensation policies and programs for executive officers and Board members. In particular the Compensation Committee is to:

review and approve corporate goals and objectives relevant to the compensation of the CEO and other executive officers

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evaluate the performance of the CEO and the other executive officers in light of the corporate goals and objectives and set compensation levels for the executive officers

recommend to the Board the approval, adoption and amendment of all incentive compensation plans in which any executive officer participates and all other equity-based plans

administer the equity-based incentive compensation plans and any other plans adopted by the Board that contemplate administration by the Compensation Committee

approve all grants of stock options and other equity-based awards

review and approve employment, severance or termination arrangements for any executive officers

review Board compensation

The Compensation Committee may, in its discretion, delegate all or a portion of its duties and responsibilities to a subcommittee or, to the extent permitted by applicable law, to any other body or individual. In particular, the Compensation Committee may delegate the approval of certain transactions to a subcommittee consisting solely of members of the Compensation Committee who are (a) non-employee directors within the meaning of Rule 16b-3 of the Securities Exchange Act of 1934, and (b) outside directors for the purpose of Section 162(m) of the Internal Revenue Code (the Code).

The process for setting director and executive compensation in 2006 involved numerous steps. In the late summer of 2005, senior management met with representatives of Towers Perrin, a nationally recognized compensation consulting firm engaged by the Compensation Committee, to discuss the Company s existing executive compensation program and potential changes to the program or any of the underlying compensation plans. In September 2005, the Company s Board of Directors received a presentation from Towers Perrin that included an annual review of director and executive compensation in the utility industry and an overview of trends and emerging issues in executive and board remuneration.

The next step in the process was an annual performance evaluation of each member of the management team. This process entailed for each member of the management team (other than the CEO) an objective scoring by such individual s supervisor of various competencies, including the individual s management skills, business knowledge and achievement of various performance and development objectives set at the beginning of the year. These reviews were used by the CEO and COO in making compensation recommendations to the Compensation Committee.

The balance of the process for setting director and executive compensation for 2006 involved actions taken by the Compensation Committee. The Compensation Committee met in November 2005, December 2005 and February 2006 to address 2006 compensation. At the November 2005 meeting, the Compensation Committee reviewed with the CEO and COO the performance evaluations of each member of management (other than the CEO), with the CEO giving his performance evaluation of the COO. The Compensation Committee at its November 2005 meeting also reviewed and discussed with the CEO and COO their recommendations for each member of management (other than the CEO) of 2006 salaries, target annual incentive awards (expressed as a percentage of salary) and target long-term incentive awards (also expressed as a percentage of salary). In addition, the Compensation Committee evaluated the CEO s performance at its November 2005 meeting and discussed his potential salary, target annual incentive award and target long-term compensation for 2006. The meeting of the Compensation Committee in November 2005 concluded without any action by the Compensation Committee on these components of 2006 executive compensation. The Compensation Committee did review and set compensation for the directors, which is described below under Director Compensation.

At the Compensation Committee s meeting in December 2005, the Compensation Committee met and set 2006 salaries and, subject to potential adjustment at its meeting in February 2006, target annual incentive awards and target long-term compensation awards for each member of management. The target annual incentive awards and target long-term compensation awards were expressed as percentages of salary. The Company performance goals that needed to be achieved for any payouts of annual incentive awards or long-term incentives were not set at this meeting; but, instead, were left for consideration at the scheduled meeting in February 2006.

Prior to the Compensation Committee s meeting in February 2006, the Company s senior management developed recommendations for the Company performance goals that needed to be met in order for any payouts of 2006 annual incentive awards or 2006 long-term compensation awards to occur.

At this meeting in February 2006, the Compensation Committee reviewed with senior management its recommendations and basis for Company performance goals for payouts of 2006 annual incentive awards and long-term compensation awards. Following this discussion, the Compensation Committee set the 2006 Company performance goals for annual incentive awards and long-term compensation awards that had to be achieved in order for payouts of such awards to occur. The Compensation Committee also approved the form of the long-term compensation awards, which, like prior years, consisted entirely of performance units.

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 nine times in 2006.

Communications with the Board of Directors. Shareowners and other interested parties 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 of the Board members attended the Annual Meeting in 2006.

Prohibition on Loans. The Company s Stock Incentive Plan prohibits all loans to executive officers.

Auditors; Audit Partner Rotation. As described on page 13, the Company is requesting that the shareowners ratify the selection of Ernst & Young LLP as the Company s principal independent accountants for 2007. 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 22 in Compensation Discussion and Analysis.

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 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.

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, appropriateness of having a member of management, in addition to the CEO, on the Board as part of the succession planning process, 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.

Director Compensation. Compensation of non-officer directors of the Company during 2006 included an annual retainer fee of $81,000, of which $2,500 was payable monthly in cash and $51,000 was deposited in the director s account under the Company s Deferred Compensation Plan in December 2006 and converted to 1300.357 common stock units based on the closing price of the Company s Common Stock on November 30, 2006. All non-officer directors received $1,200 for each Board meeting and $1,200 for each committee meeting attended. 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 2006. Each chairman of a board committee also received a meeting fee of $1,200 for each meeting (either in person or by phone) with management to address committee matters. These amounts represent the total fees paid to directors in their capacities as directors of the Company and OG&E.

Under the Company s Deferred Compensation 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 as of the first day of the month in which 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 Company s Deferred Compensation Plan. During 2006, 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 Company s Deferred Compensation Plan are paid in cash in a lump sum or installments.

Historically, for those directors who retired from the Board of Directors after ten 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.

Director Compensation

Name	Fees Earned or Paid in Cash ($)	Stock Awards ($)(1)	Option Awards ($)	Non-Equity Incentive Plan Compensation ($)	Change in Pension Value and Nonqualified Deferred Compensation Earnings ($)	All Other Compensation ($)	Total ($)
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
Herbert H. Champlin	$52,800	$51,000	0	0	0	0	$103,800
Luke R. Corbett	$75,000	$51,000	0	0	0	0	$126,000
William E. Durrett (2)	$23,300	0	0	0	0	0	$23,300
John D. Groendyke	$56,400	$51,000	0	0	0	0	$107,400
Robert Kelley	$72,400	$51,000	0	0	0	0	$123,400
Linda P. Lambert	$50,400	$51,000	0	0	0	0	$101,400
Robert O. Lorenz	$54,000	$51,000	0	0	0	0	$105,000
Ronald H. White	$56,400	$51,000	0	0	0	0	$107,400
J.D. Williams	$60,200	$51,000	0	0	0	0	$111,200

(1) Amounts in this column represent the dollar value of the annual retainer that was deposited in the director s account under the Directors Deferred Compensation Plan. As of December 31, 2006, the number of common stock units in the Company Common Stock Fund for each of the directors was as follows: Mr. Champlin, 52,690 common stock units; Mr. Corbett, 36,506 common stock units; Mr. Durrett, 22,643 common stock units; Mr. Groendyke, 9,564 common stock units; Mr. Kelley, 33,384 common stock units; Ms. Lambert, 5,067 common stock units; Mr. Lorenz, 4,804 common stock units; Mr. White, 40,442 common stock units; and Mr. Williams, 10,555 common stock units.

(2) Mr. Durrett retired from the Board in May 2006.

PROPOSAL NO. 2

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

PRINCIPAL INDEPENDENT ACCOUNTANTS FOR 2007

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, 2007. 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 LLP 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 2007. 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.

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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. 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 2006 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 2006 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 2007. 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 four meetings during 2006 and the Chairman of the Audit Committee conducted six conferences with management by telephone or in person, to discuss Audit Committee matters.

Fees for Independent Auditors

Audit Fees

Total audit fees for 2006 were $1,996,069 for the Company s 2006 financial statement audit. These fees include $682,669 for the audit of internal control over financial reporting pursuant to the requirements of Sarbanes-Oxley section 404 and $15,750 for services in support of debt and stock offerings. 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.

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 2006, this amount includes estimated billings for the completion of the 2006 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, 2006 were $89,575, of which $73,575 was for employee benefit plan audits and $16,000 for other audit-related services.

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.

Tax Fees

The aggregate fees billed for tax services for the fiscal year ended December 31, 2006 were $331,499. These fees include $239,555 for tax preparation and compliance ($74,000 for the review of federal and state tax returns and $165,555 for assistance with examinations and other return issues) and $91,944 for other tax services.

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.

All Other Fees

There were no other fees billed to the Company in 2006 or 2005 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, 2006, for filing with the SEC. The Audit Committee selected Ernst & Young LLP as the Company s independent public accountants for 2007.

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 2006, 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

Linda Petree Lambert, member

Robert O. Lorenz, member

EXECUTIVE OFFICERS COMPENSATION

The following discussion and analysis is intended to present the material principles underlying our executive compensation policies and decisions and the key factors relevant to an analysis of those policies and decisions.

COMPENSATION DISCUSSION AND ANALYSIS

General. The Compensation Committee of the Board of Directors of the Company (the Committee) administers our executive compensation program. Our executive compensation program is premised on two basic principles. First, our overall compensation levels must be sufficiently competitive to attract and retain talented leaders. At the same time, we believe that compensation should be set at reasonable and responsible levels, consistent with our continuing focus on controlling costs. Second, our executive compensation program should be substantially performance-based and should align the interests of our executives with those of our shareowners.

Three key components of our executive compensation program are salary, annual incentive awards under our Annual Incentive Compensation Plan and long-term incentive awards under our Stock Incentive Plan. Both the Annual Incentive Compensation Plan and Stock Incentive Plan were approved by our shareowners at the 2003 Annual Shareowners Meeting. Salaries are a critical element of executive compensation because they provide executives with a base level of monthly income. The Committee s intent in setting salaries is to pay competitive rates based on an individual s experience and level of performance. The annual and long-term incentive awards of an executive s compensation are directly linked to performance. Payouts of these portions of an executive s compensation are placed at risk and require the accomplishment of specific results that are designed to benefit our shareowners and the Company, both in the long and short term. Specifically, awards under the Annual Incentive Plan provide officers and key employees an opportunity to earn an annual cash bonus for achieving specified Company performance-based goals established for the year. These Company performance goals typically are tied to measures of operating performance. Awards under the Stock Incentive Plan are equity-based and require the achievement over a three-year period of specific Company performance goals that are tied directly to the performance of the Company s stock or to factors that affect the performance of the Company s stock.

Our executive compensation program recognizes that our senior executives are in a position to influence directly the Company s achievement of targeted results and strategic initiatives. For this reason, as an individual s position and responsibilities increase, a greater portion of the officer s compensation is at risk and consists of performance-based pay dependent on the achievement of performance objectives. This is shown by the level of salaries, annual incentive awards and long-term incentive awards set for our five most highly paid executive officers in 2006. For each of these executive officers, salary represented less than 60% of the potential amount that could be received through achievement, at target level, of the Company performance goals set in connection with the officer s annual and long-term incentive awards. As a result, our executive compensation program is designed to reward executives with a highly-competitive level of compensation during years of excellent Company performance and, conversely, in years of below-average performance, their compensation may be below competitive levels.

In an effort to measure the continued reasonableness and competitiveness of our executive compensation policies, the Committee in 2005 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 for 2006, the Committee considered the salaries and annual and long-term incentive awards for executives with similar duties at the 50th percentile within the following three groups: (i) Towers Perrin s 2005 Energy Services Industry Executive Compensation Database (the Energy Services Survey Group), consisting of approximately 94 energy services organizations, many of which have significant utility operations, (ii) Towers Perrin s 2005 General Industry Executive Compensation Database (the General Industry Survey Group), consisting of more than 800 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. Compensation to be paid at the 50th percentile to an executive in the General Industry Survey Group is typically higher, often significantly higher, than the compensation that would be paid to an executive with similar duties in the Energy Services Survey Group. This difference is largely attributable to higher compensation being paid in general industry as compared to the utility industry, which, as noted above, comprises a significant portion of the Energy Services Survey Group.

While the three survey groups are reviewed by our senior management in making recommendations to the Committee and by the Committee in making compensation decisions, both management and the Committee have utilized, where appropriate, the Blended Industry Survey Group for base salary, target annual incentive awards and target long-term incentive awards. The rationale for utilizing the blended industry data has been to:

Facilitate the Company s ability to attract and retain key executive talent with the desired skills sets and ranges of experience from both inside and outside the traditional utility industry;

Acknowledge the Company s business mix between utility and non-utility assets; and

Be consistent with the approach used by similar companies in the industry.

In practice, however, most utility-specific jobs (e.g., Vice President of Transmission) have no comparable jobs in general industry and can only be benchmarked to the utility industry. As a result, the Company has targeted the 50th percentile market pay data of the Blended Industry Survey Group for executives whose responsibilities are not limited to utility operations and the 50th percentile market pay data of the Energy Services Survey Group for executives whose responsibilities are limited to utility operations. This market pay data for an executive is intended to represent what would be paid to a hypothetical, seasoned performer in a job having similar responsibilities and scope, in an organization of similar size and type, to the executive in question. However, actual compensation recommendations by senior management and decisions on compensation by the Committee can vary from this market data for numerous reasons, including an individual s performance, experience level and internal equity.

An individual s performance is judged through an annual performance evaluation, which involves, for each member of senior management (other than the CEO), an objective scoring by such individual s supervisor of various competencies, including the individual s management skills, business knowledge and achievement of various performance and development objectives set at the beginning of the year. The annual performance evaluations are reviewed with the Committee and are used by the CEO and COO in making compensation recommendations to the Committee. The Committee also conducted an annual performance evaluation of the CEO.

The Committee met in December 2005 and set each executive officer s 2006 salary and, subject to potential adjustment at its meeting in February 2006, each executive officer s target annual incentive award and target long-term incentive award for 2006 based primarily on the individual s annual performance evaluation and on the comparable amounts shown at the 50th percentile for an executive officer with similar duties in the Blended Industry Group or, in the case of an executive officer whose responsibilities are limited to utility operations, in the Energy Services Survey Group. The target annual and long-term incentive awards were expressed as percentages of salary. While the setting of the target annual incentive and long-term incentive awards is an important part of the executive compensation process, another critical part is the setting of the Company performance goals for such awards. This is a critical part because the level of achievement of the Company performance goals will determine the amount, if any, of the possible payouts of the target annual and long-term incentive awards.

Following a discussion of recommendations by the CEO and COO, the Committee, at its meeting in February 2006, set the Company performance goals for annual incentive and long-term incentive awards. These Company performance goals for executive officers are described in detail below and were intended to align the executive s interests with our shareowners by having achievement of Company performance goals be directly beneficial to our shareowners. The Committee also approved the form of the long-term compensation awards, which, like recent prior years, were equity-based and consisted entirely of performance units. The Committee chose to take these actions at its meeting in February 2006 because the Committee wanted to know the Company s audited 2005 financial results before setting many of the 2006 performance goals and such audited financial results were not available until shortly before the meeting.

In setting the executive compensation for any given year, the Committee historically (including 2006) has not looked to compensation earned by executives in prior years, including specifically amounts realized from grants in prior years of annual incentive awards or long-term incentive awards. The primary reasons are that our executive compensation program seeks to have all components of executive compensation be competitive, and the portions of an executive s compensation that could vary materially from year to year are primarily performance-based. As a result, high levels of executive compensation in a particular year historically have resulted from excellent Company performance, which the Committee believed did not warrant a reduction in future compensation levels or in our compensation principles. There also is no established policy or target for the allocation between either cash and non-cash or annual and long-term compensation. Rather, the Committee reviews information from Towers Perrin to determine the appropriate level and mix of incentive compensation.

As indicated above, our senior management and, in particular our CEO and COO, played an important part in setting 2006 executive compensation. Besides developing recommendations for the Company performance goals that needed to be met for payouts of 2006 annual incentive awards and long-term incentive awards, they reviewed with the Committee at its November 2005 meeting the performance evaluations of each member of management (other than the CEO), with the CEO giving his performance evaluation of the COO. They also reviewed and discussed with the Committee at its November meeting their recommendations for each member of management (other than the CEO) of 2006 salaries, target annual incentive awards and target long-term incentive awards. As noted above, the CEO s performance evaluation and the setting of his potential salary, target annual incentive award and target long-term incentive award were conducted by the Committee without any members of management present. The Committee s performance evaluation of the CEO, along with his 2006 salary, target annual incentive award and target long-term incentive award, were reviewed by the Committee with all independent members of the Board.

The following three sections illustrate the application of our executive compensation principles and discuss in detail the salaries, bonuses and long-term compensation that were approved by the Committee and were paid in connection with 2006 compensation.

Base Salary. As explained above, the base salaries for our executive officers in 2006 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 whose responsibilities are limited to utility operations. Base salaries of our executive officers were determined based primarily on an individual s annual performance evaluation and the salaries at the 50th percentile of the range for executives with similar duties in the appropriate survey group. The salaries of executive officers for 2006 were initially determined in December 2005, with an effective date of January 1, 2006. The 2006 base salary amounts for the most highly compensated executive officers are shown in the salary column of the Summary Compensation Table on page 23. The percentage increase (decrease) in salaries for these individuals was as follows: Steven Moore, 4%; Peter Delaney, 7%; James Hatfield, 6%; Dan Harris, 9%; and Steven Gerdes, (5%).

Annual Incentive Compensation. Annual incentive awards with respect to 2006 performance were made under the Annual Incentive Compensation Plan to 90 employees, including all executive officers. The Plan provides key management personnel with annual incentive awards, the payment of which is dependent entirely on the achievement of the Company performance goals that, for 2006, were established by the Committee in February 2006.

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 Company performance goals, to receive from 0% to 150% of such targeted amount. For 2006, the targeted amounts ranged from 30% to 85% of base salary for executive officers and were at or slightly below the 50th percentile of the level of such awards granted to comparable executives in the Blended Industry Survey Group or, in the case of executive officers whose responsibilities are limited to utility operations, to comparable executives in the Energy Services Survey Group. For the most highly compensated executives reported in the Summary Compensation Table on page 23, the targeted amounts were as follows: Mr. Moore, 85% of his 2006 salary; Mr. Delaney, 70% of his 2006 salary; Mr. Hatfield, 55% of his 2006 salary; Mr. Harris, 40% of his 2006 salary; and Mr. Gerdes, 30% of his 2006 salary.

As noted above, potential payouts of targeted amounts are dependent entirely on achievement of Company performance goals. For Messrs. Moore and Delaney, the two most senior executive officers of the Company, the Company performance 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) established by the Committee. At least two of these three Company performance goals were used in establishing the corporate goals for all other executive officers. However, the weighting of the Company performance goals was slightly different for the remaining executive officers based on their responsibilities. For two executive officers whose responsibilities pertain primarily or exclusively to utility operations, the Company performance 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 Company performance goals were based 40% on the Earnings Target, 40% on the Unregulated Income Target and 20% on a return on invested capital target for Enogex (the ROIC Target) established by the Committee. For the remaining executive officers, the Company performance goals were based 50% on the Earnings Target, 30% on the O&M/Capital Target and 20% on the Unregulated Income Target.

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For each Company performance goal, the Committee established a minimum level of performance (below which no payout would be made), a target level of performance (at which a 100% payout would be made) and a maximum level of performance (at or above which a 150% payout would be made). The following table shows the target levels of performance for the four Company performance goals set for executive officers in 2006, the actual level of performance, as calculated pursuant to the terms of the awards, and the percentage payout of the targeted amount based on the actual level of performance:

	Target	Actual Performance	% Payout
Earnings Target (1)	$1.86/share	$2.45/share	150.00%
O&M/ Capital Target (1)	$307 million/ $247 million	$306.8 million/ $245.3 million	100.94%
Unregulated Income Target	$50.1 million	$76.2 million	150.00%
ROIC Target (1)	8.36 %	11.74%	150.00%

(1) As indicated above, calculation of the Earnings Target, O&M/Capital Target and Unregulated Income Target are derived from the Company s financial statements, with the Earnings Target being the Company s reported consolidated diluted earnings per share from continuing operations, the Unregulated Income Target being the reported consolidated net income of Enogex from continuing operations, the O&M/Capital Target being the operating and maintenance expenditures and capital expenditures of various OGE Energy and OG&E business units and ROIC being generally the sum of consolidated net operating profit less adjusted taxes of Enogex divided by the amount of Enogex s average invested capital. Notwithstanding the foregoing, the Committee at the time of setting these Company performance goals specifically excluded various items in calculating the achievement of these performance goals, including, for example, increases or decreases in revenues, expenses, gains or losses from any change in accounting principles occurring during 2006 and any gains or losses from the sale, other disposition or impairment of any business or asset during 2006. While the overall effect of these exclusions was to lower Enogex s consolidated net income from continuing operations from the $77.5 million reported in Enogex s financial statements to $76.2 million, the exclusions had no effect on the payouts to executive officers of the Earnings Target, O&M/Capital Target, Unregulated Income Target or the ROIC Target.

The percentage of the targeted amount that an executive officer ultimately received based on corporate performance was subject to being decreased, but not increased, at the discretion of the Committee. For 2006, corporate performance of the Earnings Target, the ROIC Target, the O&M/Capital Target and the Unregulated Income Target exceeded the minimum levels of achievement established by the Committee and, based on the level of achievement, the Committee approved payouts under the Annual Incentive Compensation Plan to executive officers ranging from approximately 35% to 117% of their base salaries and from approximately 116% to 150% of their targeted amounts. Payouts under the Annual Incentive Compensation Plan are in cash and the amounts paid to the Company s most highly compensated executive officers are reflected in the Non-Equity Incentive Plan Compensation column of the Summary Compensation Table on page 23.

Long-Term Incentive Compensation. Long-term incentive awards also were made in 2006 under our Company s Stock Incentive Plan. 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 2006, the Committee set a targeted amount of long-term incentive compensation to be awarded each executive officer, which amount was expressed as a percentage of the individual s base salary as of January 1, 2006. For 2006, the targeted amount ranged from 30% to 150% of base salary for executive officers and was at or below the 50th percentile of the level of such awards granted to comparable executives in the Blended Industry Survey Group or, in the case of executive officers whose responsibilities are limited to utility operations, to comparable executives in the Energy Services Survey Group. The targeted amount (expressed as a percentage of salary) of long-term incentive compensation for several executive officers of the Company was set by the Committee more than 10% below the level of such awards granted to comparable executives in the appropriate survey group. This action by the Committee was due to long-term compensation for comparable executives in the appropriate survey group being substantially higher than the amounts awarded by the Committee in the past to such executives of the Company and the Committee s

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desire to make up such shortfall over a period of several years rather than through a substantial increase in a particular year. For the most highly compensated executives reported in the Summary Compensation Table on page 23, the targeted amounts of long-term incentive compensation were as follows: Mr. Moore, 150% of his 2006 salary; Mr. Delaney, 120% of his 2006 salary; Mr. Hatfield, 85% of his 2006 salary; Mr. Harris, 55% of his 2006 salary; and Mr. Gerdes, 35% of his 2006 salary.

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, for both 2005 and 2006, awarded all long-term compensation in the form of performance units, with, as explained below, payout of the performance units being dependent on achievement of Company performance goals set by the Committee. Specifically, for 75% of the performance units awarded in 2006, the Company performance goal is based on the relative total shareholder return (TSR) of the Company s Common Stock over the three-year period ending December 31, 2008 compared to a peer group and, for the remaining 25%, the Company performance goal is based 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 on February 22, 2006, immediately following the Committee s meeting on such date. 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 2006 base salary and as determined above) and dividing that amount by $19.734, which was the value of a performance unit computed in a manner consistent with SFAS No. 123(R) based on a recent closing price of the Company s Common Stock of $26.50 per share. This resulted in executives receiving a number of performance units with an expected value at the date of grant from 0% to 150% of their 2006 base salaries. All payouts of such performance units will be made in shares of the Company s Common Stock, which causes the value of the performance units to be 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 to each executive officer in 2006 entitle the officer to receive from 0% to 200% of the performance units granted depending upon the Company s TSR over a three-year period (defined as share price increase (decrease) since December 31, 2005 plus dividends paid, divided by share price at December 31, 2005) measured against the TSR for such period of 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, 2008), 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 50th percentile of the peer group, with higher payouts for performance above the 50th percentile up to 200% of the performance units granted if the Company s TSR is at or above the 90th 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 50th percentile of the peer group, with no payout for performance below the 35th percentile.

For the remaining 25% of performance units granted to each executive officer in 2006, the officer is entitled to receive from 0% to 200% of the performance units granted depending upon the growth in the Company s earnings per share over the three-year period ending December 31, 2008. The growth in the earnings per share will be measured from $1.83 per share (which consisted of the $1.77 earned in 2005 from continuing operations plus $0.06 per share for a one time event in 2005 that lowered earnings from continuing operations by $0.06 per share) against the Earnings Growth Target (4% per year) set by the Committee for such period. At the end of the three-year period (i.e., December 31, 2008), 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. The Company s earnings growth rate is calculated on a point-to-point basis by dividing by one-third the percentage increase in the Company s earnings per share for the year ended December 31, 2008, compared to the benchmark of $1.83 for 2005.

In January 2004, as part of their long-term compensation executive officers received performance units whose payout was dependent on the achievement of a Company performance goal based on TSR for the three-year period ended December 31, 2006. The Company s TSR for such period was at the 77.70th percentile (approximately the top 23%) of the peer group. Stated differently, the percentage return on the Company s Common Stock, consisting of increases (decreases) in the price of the Company s Common Stock plus dividends paid, was higher than 77.70% of the companies in the Standard & Poor s Utility Index during the period commencing on January 1, 2004 and ending on December 31, 2006. This high level of performance resulted in payouts in February 2007 of 169.25% of the performance units originally awarded in January 2004. The value of these payouts is reflected in the Stock Awards Value Realized on Vesting column of the Option Exercises and Stock Vested Table on page 26.

CEO Compensation. The 2006 compensation for Mr. Moore consisted of the same components as the compensation for other executive officers. Mr. Moore s 2006 salary was increased from $750,000 to $780,000, and his 2006 targeted award under the Annual Incentive Plan, was increased from 80% to 85% of his base salary, which the Committee believed were appropriate levels based on his performance and the amounts paid to a chief executive officer in the Blended Industry Survey Group. As a result of 2006 corporate performance of the corporate goals described above, he received a payout of $913,183 under the Annual Incentive Plan, representing approximately 117% of his base salary and 137.74% of his targeted award. Mr. Moore also received as long-term compensation in February 2006 an award of 59,288 performance units, having an estimated value of 150% of his 2006 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 2006 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 50th percentile of the Energy Services Survey Group and of the Blended Industry 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 2007 a payout of 169.25% of the performance units granted to Mr. Moore in January 2004 based on the Company s TSR for the three years ended December 31, 2006 being at the 77.70th percentile (approximately the top 23%) of the peer group selected by the Committee. This resulted in Mr. Moore receiving a payout of 61,566 units, of which two-thirds (41,044) were paid in shares of the Company s Common Stock and one-third (20,522) was paid in cash based on the high and low prices of the Company s Common Stock on the date the Committee approved the payout. The value of this payout, based on the closing price of the Company s Common Stock on December 31, 2006, is reported in the Stock Awards Value Realized on Vesting column of the Option Exercises and Stock Vested Table on page 26.

Other Benefits. As noted above, the key components of our executive compensation program are salary, annual incentive awards and long-term incentive awards. Virtually all of our employees, including executive officers, are eligible to participate in our pension plan and supplemental restoration plan that enables participants, including executive officers, to receive the same benefits that they would have received under our pension plan in the absence of limitations imposed by the federal tax laws. In addition, a Supplemental Executive Retirement Plan (the SERP), which was adopted in 1993, offers supplemental pension benefits to specified lateral hires. Mr. Delaney is the only executive officer who participates in the SERP. Mr. Delaney s participation in the SERP was the result of arms-length bargaining between Mr. Delaney and the Company at the time of his hire in April 2002 as Executive Vice President of the Company. For additional information on the pension plan, restoration plan and SERP, see Pension Benefits below.

Almost all employees of the Company, including the executive officers, also are eligible to participate in our tax-qualified defined contribution savings plan (the Retirement Savings Plan). Under the Retirement Savings Plan, participants may contribute between two percent and 19 percent of their compensation. Participants may designate, at their discretion, all or any portion of their contributions as: (i) a before-tax contribution under Section 401(k) of the Code subject to the limitations thereof; or (ii) a contribution made on an after-tax basis. The Company will match, depending upon the participant s years of service and date of initial participation, 50 percent, 75 percent or 100 percent of the first six percent of compensation. Participants contributions are fully vested and non-forfeitable. The Company match contributions vest over a six-year period. After two years of service, participants become 20 percent vested in their Company contribution account and vest an additional 20 percent for each subsequent year of service. In addition, participants fully vest when they are eligible for normal or early retirement under the Company s pension plan, in the event of their termination due to death, permanent disability or upon attainment of age 65 while employed by the Company or its affiliates.

The Company also maintains a non-qualified deferred compensation plan that is described below under Nonqualified Deferred Compensation.

The Company also offers executive officers a limited amount of perquisites. These include up to $7,500 annually for tax and financial planning services, payment of dues at luncheon and country clubs, reimbursement for liability insurance, an annual physical exam and, in the case of Mr. Moore, a leased car. The value of the perquisites received by each executive officer, other than Mr. Moore, was less than $10,000 in 2006. In reviewing the perquisites and benefits under the SERP, Retirement Savings Plan, deferred compensation plan, pension plan and related restoration plan, the Committee sought in 2006 to provide participants with benefits at least commensurate with those offered by other utilities of comparable size.

Change-of-Control Provisions. Each of the executive officers has an employment agreement that provides for specified benefits upon termination following a change of control. These employment agreements are described in detail below under the heading Potential Payments Upon Termination or Change of Control. In addition, pursuant to the terms of the Company s incentive compensation plans, upon a change of control, all stock options will vest immediately and, for a 60-day period following the change of control, executive officers may surrender their options and receive in return a cash payment equal to the excess of the change of control price (as defined) over the exercise price; all performance units will vest and be paid out immediately in cash as if the applicable performance goals had been satisfied at target levels; and any annual incentive award outstanding at the participant s termination for any reason other than cause within 24 months after the change of control will be paid in cash at target level on a prorated basis.

Stock Ownership Guidelines. In an effort to further align management s interests with those of the share-owners, 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 and CEO 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. Similar guidelines were adopted for members of the Board of Directors at a level of five times their annual retainer.

Financial Restatement. It is the Board of Directors policy that the Compensation Committee will, to the extent permitted by governing law, have the sole and absolute authority to make retroactive adjustment to any cash or equity-based incentive compensation paid to executive officers and certain other officers where the payment was predicated upon the achievement of certain financial results that were subsequently the subject of a restatement. Where applicable, the Company will seek to recover any amount determined to have been inappropriately received by the individual executive.

Tax and Accounting Issues.

Deductibility of Executive Compensation. 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.

Nonqualified Deferred Compensation. On October 22, 2004, the American Jobs Creation Act of 2004 was signed into law, changing the tax rules applicable to nonqualified deferred compensation arrangements. While the final regulations have not become effective yet, the Company believes it is operating in good faith compliance with the statutory provisions which were effective January 1, 2005. A more detailed discussion of the Company s nonqualified deferred compensation arrangements is provided below under the heading Nonqualified Deferred Compensation.

Accounting for Stock-Based Compensation. Beginning on January 1, 2006, the Company began accounting for stock-based payments, including its stock options and performance units, in accordance with the requirements of Statement of Financial Accounting Standards No. 123(R), Share-Based Payment.

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, the Chief Financial Officer and the three other most highly compensated executive officers for 2006.

	Year	Salary ($)	Bonus ($)	Stock Awards ($) (1)	Option Awards ($) (2)	Non-Equity Incentive Plan Compensation ($) (3)	Change in Pension Value and Nonq fied Deferred Compensation Earnin ($) (4)
	(b)	(c)	(d)	(e)	(f)	(g)	(h)
(6)	2006	$780,000	0	$2,538,567	$19,384	$913,183	$410,186
r (7)	2006	$510,000	0	$1,366,449	$10,022	$491,714	$582,898
	2006	$370,700	0	$646,150	$4,806	$275,820	$61,694
resident and Chief Operating Officer, Enogex, Inc.	2006	$284,000	0	$262,992	$1,549	$170,400	$55,659
	2006	$210,000	0	$250,646	$2,209	$79,046	$15,859

sation Plan) and $11,660 (insurance premiums). A significant portion of the insurance premiums reported for each of these individuals is for life insurance policies ar

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Grants of Plan-Based Awards Table

Name	Grant Date	Estimated Future Payouts Under Non-Equity Incentive Plan Awards			Estimated Future Payouts Under Equity Incentive Plan Awards			All Other Stock Awards: Number of Shares of Stock or Units	All Other Option Awards: Number of Securities Underlying Options	Exercise or Base Price of Option Awards	Grant Date Fair Value of Stock and Option Awards
		Threshold ($)	Target ($)	Maximum ($)	Threshold ($)	Target ($)	Maximum ($)	(#)	(#)	($/Sh)	($)
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
S.E. Moore	2/22/2006				0	44,466	88,932	N/A	N/A	N/A	$1,019,605
	2/22/2006				0	14,822	29,644	N/A	N/A	N/A	415,016
	2/22/2006	0	663,000	994,500							
P.B. Delaney	2/22/2006				0	23,259	46,518	N/A	N/A	N/A	$533,329
	2/22/2006				0	7,753	15,506	N/A	N/A	N/A	217,084
	2/22/2006	0	357,000	535,500							
J.R. Hatfield	2/22/2006				0	11,975	23,950	N/A	N/A	N/A	$274,587
	2/22/2006				0	3,992	7,984	N/A	N/A	N/A	111,776
	2/22/2006	0	203,885	305,828							
D.P. Harris	2/22/2006				0	5,936	11,872	N/A	N/A	N/A	$136,112
	2/22/2006				0	1,979	3,958	N/A	N/A	N/A	55,412
	2/22/2006	0	113,600	170,400							
S.R. Gerdes	2/22/2006				0	2,793	5,586	N/A	N/A	N/A	$64,043
	2/22/2006				0	931	1,862	N/A	N/A	N/A	26,068
	2/22/2006	0	63,000	94,500							

Amounts in columns (c), (d) and (e) of the Grants of Plan-Based Awards table above represent the minimum, target and maximum amounts that would be payable pursuant to the 2006 annual incentive awards made under the Annual Incentive Compensation Plan. As described in the Compensation Discussion and Analysis section above, the amount that each executive officer received was dependent upon performance against two or more of the following performance measures: Earnings Target, O&M/Capital Target, Unregulated Income Target and ROIC Target. For each Company performance measure, the Compensation Committee established a minimum level of performance (below which no payout would be made), a target level of performance (at which a 100% payout would be made) and a maximum level of performance (at or above which a 150% payout would be made). The percentage of the targeted amount that an executive officer ultimately received based on corporate performance was subject to being decreased, but not increased, at the discretion of the Committee. For 2006, payouts of these annual incentive awards were made in cash and are reflected in the Non-Equity Incentive Plan Compensation column of the Summary Compensation Table.

Amounts in columns (f), (g) and (h) above represent awards of performance units under the Company s Stock Incentive Plan. All payouts of such performance units will be made in shares of the Company s Common Stock. As described in more detail in the Compensation Discussion and Analysis section above, the terms of 75% of the performance units granted to each executive officer in 2006 entitle the officer to receive from 0% to 200% of the performance units granted depending upon the Company s TSR over a three-year period measured against the TSR for such period by a peer group selected by the Committee. At the end of the three-year period (i.e., December 31, 2008), 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 50th percentile of the peer group, with higher payouts for performance above the 50th percentile up to 200% of the performance units granted if the Company s TSR is at or above the 90th 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 50th percentile of the peer group, with no payout for performance below the 35th percentile.

For the remaining 25% of performance units granted in 2006, 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 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, 2008), 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. The Company s earnings growth rate is calculated on a point-to-point basis by dividing by one-third the percentage increase in the Company s earnings per share for the year ended December 31, 2008, compared to the benchmark of $1.83 for 2005.

Based on the fair value of equity awards granted to the named executive officers in 2006 and the base salary of the named executive officers, Salary accounted for approximately 30% to 60% of total compensation, while incentive compensation accounted for approximately 40% to 70% of the total compensation, assuming achievement of a target level of performance for each named executive officer. Because the value of certain equity awards included in the Summary Compensation Table is based on the FAS 123R value rather than fair value, these percentages may not be able to be derived using the amounts reflected in the Summary Compensation Table.

Outstanding Equity Awards at Fiscal Year-End Table

	Option Awards					Stock Awards			
Name	Number Of Securities Underlying Unexercised Options Exercisable (#)	Number of Securities Underlying Unexercised Options Unexerciseable (#)	Equity Incentive Plan Awards: Number of Securities Underlying Unexercised Unearned Options (#)	Option Exercise Price ($)	Option Expiration Date	Number of Shares or Units of Stock That Have Not Vested (#)	Market Value of Shares or Units of Stock That Have Not Vested ($)	Equity Incentive Plan Awards: Number of Unearned Shares, Units or Other Rights That Have Not Vested (#)	Equity Incentive Plan Awards: Market or Payout Value of Unearned Shares, Units or Other Rights That Have Not Vested ($)(1)
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
S.E. Moore	56,733	28,367(2)	0	23.575	1/21/2014			59,288(3)	$2,371,520
	202,300	0	0	16.685	1/27/2013			47,301(4)	$1,892,040
	218,500	0	0	22.230	1/16/2012				
	104,700	0	0	22.500	1/17/2011				
	77,800	0	0	18.250	1/19/2010				
	72,800	0	0	28.750	1/20/2009				
	104,000	0	0	25.750	1/21/2008				
P.B. Delaney	29,333	14,667(2)	0	23.575	1/21/2014			31,012(3)	$1,240,480

	43,200	0	0	16.685	1/27/2013	26,961(4)	$1,078,440
	84,900	0	0	22.700	3/15/2012		
J.R. Hatfield	7,033	7,034(2)	0	23.575	1/21/2014	15,967(3)	$638,680
	1	0	0	16.685	1/27/2013	11,920(4)	$476,800
D.P. Harris	4,533	2,267(2)	0	23.575	1/21/2014	7,915(3)	$316,600
	10,934	0	0	16.685	1/27/2013	5,087(4)	$203,480
	5,567	0	0	22.230	1/16/2012		
S.R. Gerdes	0	3,234(2)	0	23.575	1/21/2014	3,724(3)	$148,960
						5,087(4)	$203,480

(1) Values were calculated based on a $40.00 closing price of OGE Energy Common Stock, as reported on the New York Stock Exchange at December 29, 2006.
(2) These options vested over three years with the final third becoming exercisable at January 21, 2007.
(3) These amounts represent performance units for the performance period January 1, 2006 to December 31, 2008.
(4) These amounts represent performance units for the performance period January 1, 2005 to December 31, 2007.

Option Exercises and Stock Vested Table

Name	Option Awards Number of Shares Acquired on Exercise (#)	Value Realized on Exercise ($)	Stock Awards Number of Shares Acquired on Vesting (#) (1)	Value Realized on Vesting ($)
(a)	(b)	(c)	(d)	(e)
S.E. Moore	N/A	N/A	61,566	$2,379,526
P.B. Delaney	45,000	$633,989	31,795	$1,228,877
J.R. Hatfield	17,266	$253,555	15,233	$588,755
D.P. Harris	N/A	N/A	4,942	$191,008
S.R. Gerdes	49,400	$584,390	6,993	$270,279

(1) Reflects value of payout of performance units awarded in January 2004, whose payout was dependent on the achievement of a Company performance goal based on TSR for the three-year period ended December 31, 2006. The Company s TSR for such period was at the 77.70th percentile (approximately the top 23%) of the peer group, which resulted in payouts in February 2007 of 169.25% of the performance units originally awarded in January 2004.

Pension Benefits Table

Name	Plan Name	Number of Years Credited Service (#)	Present Value of Accumulated Benefit ($)(1)	Payments During Last Fiscal Year ($)
(a)	(b)	(c)	(d)	(e)
S.E. Moore	Qualified Plan	32.50	$885,324	$0
	Restoration Plan	32.50	$5,337,251	$0
P.B. Delaney	Qualified Plan	4.75	$53,236	$0
	Restoration Plan	4.75	$109,968	$0
	SERP	7.75	$3,260,426	$0
J.R. Hatfield	Qualified Plan	12.33	$179,540	$0
	Restoration Plan	12.33	$311,812	$0
D.P. Harris	Qualified Plan	10.67	$175,168	$0
	Restoration Plan	10.67	$152,624	$0

S.R. Gerdes	Qualified Plan	28.00	$439,039	$0
	Restoration Plan	28.00	$114,055	$0

(1) Amounts in this column reflect the present value of the named executive officer s benefits under all pension plans established by the Company determined using interest rate and mortality rate assumptions consistent with those used in Note 15 to our Consolidated Financial Statements included in our Form 10-K for the year ended December 31, 2006, and includes amounts which the named executive officer may not currently be entitled to receive because such amounts are not vested.

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 Code, benefits payable under the Retirement Plan to employees hired prior to February 1, 2000 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 annual bonus or incentive compensation) 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, annual bonuses or incentive compensation 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 the time of retirement to receive, in lieu of an annuity, a lump-sum payment equal to the present value of the annuity. For employees hired after January 31, 2000, however, the Retirement 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 described above. 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 (or, if elected, following termination) upon total and permanent disability. Of the named executive officers, Mr. Moore is eligible for early retirement. As indicated above, the benefits payable under the Retirement Plan are subject to maximum limitations under the Code. Should benefits for a participant at the time of retirement exceed the then permissible limits of the Code, the Retirement Restoration Plan will provide benefits through a lump-sum distribution or in monthly installments for a specified period of years actuarially equivalent to the amounts that would have been, but cannot be, payable to such participant annually under the Retirement Plan because of the Code limits. The Company and OG&E fund the estimated benefits payable under the Retirement Restoration Plan through contributions to a grantor trust for the benefit of those employees who will be entitled to receive payments under the Retirement Restoration Plan.

In 1993, OG&E adopted a SERP which is an unfunded supplemental plan that is not subject to the benefits limit imposed by the Code. 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 Retirement 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 2006.

Nonqualified Deferred Compensation Table

Name	Executive Contributions in Last FY ($)(1)	Registrant Contributions in Last FY ($)	Aggregate Earnings in Last FY ($)	Aggregate Withdrawals/ Distributions ($)	Aggregate Balance at Last FYE ($)
(a)	(b)	(c)	(d)	(e)	(f)
S.E. Moore	$537,315	$51,948	$631,930	$40,000	$4,318,690
P.B. Delaney	$317,700	$37,164	$125,305	0	$1,112,626
J.R. Hatfield	$21,727	$9,267	$49,948	0	$235,301
D.P. Harris	$93,296	$4,657	$40,412	0	$384,348
S.R. Gerdes	$2,258	$1,693	$12,243	$7,913	$50,140

(1) Reflects the following amounts for each of the following executive officers which is reported as compensation to such executive officer in the Summary Compensation Table on page 23: S.E. Moore, $537,315; P.B. Delaney, $317,700; J.R. Hatfield, $21,727; D.P. Harris, $93,296; and S.R. Gerdes $2,258.

The Company has a nonqualified deferred compensation plan that allows key employees, including all executive officers, to defer compensation above government limitations on 401(k) contributions that apply to the Company s qualified Retirement Savings Plan and to defer taxation on all earnings on compensation deferred into the plan. Under the terms of the nonqualified deferred compensation plan, participants have the opportunity to elect to defer each year up to 70% of their base salary and up to 100% of their bonus.

The Company matches deferrals to make up for any match lost in the Retirement Savings Plan because of deferrals to the deferred compensation plan, and to allow for a match on that portion of the first 6% of total compensation deferred that exceeds the limits allowed in the Retirement Savings Plan. Matching credits vest based on years of service, with full vesting after six years or, if earlier, on retirement, disability, death, a change in control of the Company or termination of the plan.

Deferrals, plus any Company match, are credited to a special recordkeeping account in the participant s name. Earnings on the deferrals are indexed to the assumed investment funds selected by the participant. For 2006, those investment fund options included an OGE Energy Common Stock fund; 500 Index B (MFC Global Investment); Active Bond (John Hancock Advisers, Inc.); Blue Chip Growth (T. Rowe Price); Capital Appreciation (Jennison Associates LLC); Equity-Income (T. Rowe Price); Growth & Income (Grantham, Mayo, Van Otterloo & Co.); Managed (GMO/DMR); Money Market B (MFC Global Investment); Overseas Equity (Capital Guardian Trust Company); and Small Cap Growth (Wellington Management). For 2006, those investment funds had returns of 49.31 percent; 15.56 percent; 4.54 percent; 9.59 percent; 2.38 percent; 19.05 percent; 12.72 percent; 7.48 percent; 4.70 percent; 19.76 percent and 13.47 percent.

Normally, payments under the deferred compensation plan begin within one year after retirement. For these purposes, normal retirement age is 65 and the minimum age to qualify for early retirement is age 55 with at least five years of service. Benefits will be paid, at the election of the participant, either in a lump sum or a stream of annual payments for up to 15 years, or a combination thereof. Participants whose employment terminates before they qualify for retirement benefits will receive their vested account balance in one lump sum following termination. Participants also will be entitled to pre- and post-retirement survivor benefits. If the participant dies while in employment before retirement, his or her beneficiary will receive a payment of the account balance plus a supplemental survivor benefit equal to two times the total amount of base salary and bonuses deferred under the plan. If the

participant dies following retirement, his or her beneficiary will continue to receive the remaining vested account balance. Additionally, eligible surviving spouses will be entitled to a lifetime survivor annuity payable annually. The amount of the annuity is based on 50% of the participant s account balance at retirement, the spouse s age and actuarial assumptions established by the Company s benefit committee.

At any time prior to retirement, a participant may withdraw all or part of amounts attributable to his or her vested account balance at December 31, 2004, subject to a penalty of 10% of the amount withdrawn. In addition, at the time of the initial deferral election, a participant may elect to receive one or more in-service distributions on specified dates without penalty. Hardship withdrawals, without penalty, of amounts attributable to a participant s vested account balance as of December 31, 2004 may also be permitted at the discretion of the Company s benefits committee.

COMPENSATION COMMITTEE REPORT

The Compensation Committee oversees (i) the compensation of the Company s directors and principal officers, (ii) the Company s executive compensation policy and (iii) the Company s benefit programs.

The Compensation Committee has six 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 Compensation Committee has reviewed and discussed with management the Compensation Discussion and Analysis appearing elsewhere in this proxy statement. Based on the review and discussions referred to above, the Compensation Committee recommended to the Company s Board of Directors that the Compensation Discussion and Analysis be included in the Company s Proxy Statement on Schedule 14A.

Compensation Committee

Luke R. Corbett, Chairman

Herbert H. Champlin, Member

John D. Groendyke, Member

Robert Kelley, Member

Ronald H. White, M.D., Member

J. D. Williams, Member

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POTENTIAL PAYMENTS UPON TERMINATION OR CHANGE OF CONTROL

The Company and OG&E have entered into employment agreements with each officer of the Company and OG&E that will become effective only upon a change of control of the Company. Under the agreements, a change of control generally means (i) any acquisition of 20% or more of the Company s Common Stock (subject to limited exceptions for acquisitions directly from the Company, acquisitions by the Company or one of the Company s employee benefit plans, or acquisitions pursuant to specified business combinations approved by a majority of the incumbent directors), (ii) directors of the Company as of the date of the agreements and those directors who have been elected subsequently and whose nomination was approved by such directors fail to constitute a majority of the Board, (iii) a merger, share exchange or sale of all or substantially all of the assets of the Company (each, a business combination) (except specified business combinations approved by a majority of the incumbent directors), or (iv) shareowner approval of a complete liquidation or dissolution 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 (i) such officer prior to the change of control or (ii) if more favorable, 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 employer terminates the officer s employment for reasons other than cause or disability or if the officer terminates his or her employment for good reason, the officer is entitled to the following payments: (i) all accrued and unpaid compensation and, to the extent not otherwise paid, a prorated annual bonus 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 these 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 Code, then the severance benefits will be reduced to the extent where no excise tax would be payable 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. For these purposes, good reason means (i) a diminution in the officer s position, authority, duties or responsibilities, (ii) a failure by the Company to comply with specified provisions of the employment agreement, (iii) the officer is required to be based at a different office or location 50 miles or more away or is required to travel to a substantially greater extent, and (iv) any purported termination by the Company of the officer s employment other than as expressly permitted by the employment agreement. In addition, a termination by the officer for any reason during the 30-day period following the first anniversary of the change of control will be deemed a termination for good reason.

Assuming that a change of control had occurred and the named executive officers were terminated on December 31, 2006 and that the price of OGE Energy s Common Stock was $40.00 (the closing price on December 29, 2006, the last business day of 2006), then the named executive officers would be entitled to the following lump sum severance payments under their employment agreements: S.E. Moore, $3,105,017; P.B. Delaney, $1,875,287; J.R. Hatfield, $1,330,325; D.P. Harris, $940,401; and S.R. Gerdes, $713,809. For these purposes, we have assumed that the payments would not result in the imposition of the excise tax on excess parachute payments, which if triggered, could result in a reduction of the foregoing amounts. The named executive officers would also be entitled to outplacement services, valued at approximately $50,000 each, and continued welfare benefits for three years at a value of approximately $31,000 each. For these purposes we have assumed that health care costs will increase at the rate of 9% per year. These officers also would be entitled to the retirement benefits they would otherwise be entitled to receive as set forth in the Pension Benefits table on page 26 and, as described above, Mr. Delaney would be considered vested under the SERP. Finally, matching credits under the nonqualified deferred compensation plan would vest and the officers would be entitled to the benefits set forth in the Nonqualified Deferred Compensation table on page 28.

In addition, pursuant to the terms of the Company s incentive compensation plans, upon a change of control, all stock options and restricted stock will vest immediately and, for a 60-day period following the change of control, executive officers may surrender their options and receive in return a cash payment equal to the excess of the change of control price (as defined) over the exercise price; all performance units will vest and be paid out

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immediately in cash as if the applicable performance goals had been obtained at target levels; and any annual incentive award outstanding at the participant s termination for any reason other than cause within 24 months after the change of control will be paid in cash at target level on a prorated basis. Although all outstanding stock options are already exercisable, upon a change of control, executive officers could surrender their options and receive a cash payment equal to the excess of the change of control price over the exercise price. Assuming that a change of control occurred on December 31, 2006 and that the price of our common stock (and the change of control price) was $40.00 (the closing price on December 29, 2006, the last business day of 2006), then the named executive officers would be entitled to the following lump sum payments for outstanding stock options and performance unit awards: S.E. Moore, $22,548,737; P.B. Delaney, $6,789,398; J.R. Hatfield, $1,955,874; D.P. Harris, $1,183,302; and S.R. Gerdes, $685,278.

If a named executive officer terminates employment other than following a change of control, such officer will be entitled to receive amounts earned during the course of his or her employment, including accrued salary and unpaid salary and unused vacation pay. If the termination was a result of death, disability or retirement, the executive officer could exercise his or her stock options generally for three years or their stated term, if less, and would be entitled to a regular payout of any earned annual and long-term awards whose performance periods had ended prior to the individual s termination, and to a pro-rated payout (based on the individual s number of full months of employment during the applicable performance period) for other outstanding annual and long-term incentive awards when and if payouts of such awards are subsequently earned and are made to participants who did not terminate their employment. Assuming that the named executive officers terminated their employment as a result of death, disability or retirement on December 31, 2006, each executive officer would have received the same payout of the earned annual incentive compensation for 2006 that is set forth in the Non-Equity Incentive Plan Compensation column of the Summary Compensation Table on page 23 and the same payout of long-term compensation for the performance units whose three-year performance period ended December 31, 2006 as reflected in the Stock Awards - Value Realized on Vesting column in the Option Exercises and Stock Vested Table on page 26. The reason for the same payouts is that the individual would have been employed throughout the entire performance period for the awards. If the named executive officer elects to exercise his options at the time of termination and, assuming that the price of our common stock was $40.00 (the closing price on December 29, 2006, the last business day of 2006), then the value realized on the exercise of the options for the named executive officers would be as follows: S.E. Moore, $15,822,537; P.B. Delaney, $3,198,678; J.R. Hatfield, $231,074; D.P. Harris, $465,542; and S.R. Gerdes, $53,118. In addition, for the outstanding grants of performance units whose performance periods end on December 31, 2007 and December 31, 2008 and assuming that the named executive officers terminated their employment as a result of death, disability or retirement on December 31, 2006, that the applicable goals for such performance units were subsequently satisfied at target levels and that the price of OGE Energy s Common Stock was $40.00 (the closing price on December 29, 2006, the last business day of 2006) at the time payouts of such performance units occurred, then the named executive officers would be entitled to receive Common Stock of the Company having the following values at the time payout of such performance units occurred: S.E. Moore, $1,261,360 for the performance units whose performance period ends December 31, 2007 and $790,520 for the performance units whose performance period ends December 31, 2008; P.B. Delaney, $718,960 for the performance units whose performance period ends December 31, 2007 and $413,480 for the performance units whose performance period ends December 31, 2008; J.R. Hatfield, $317,880 for the performance units whose performance period ends December 31, 2007 and $212,880 for the performance units whose performance period ends December 31, 2008; D.P. Harris, $135,640 for the performance units whose performance period ends December 31, 2007 and $105,520 for the performance units whose performance period ends December 31, 2008; and S.R. Gerdes, $135,640 for the performance units whose performance period ends December 31, 2007 and $49,640 for the performance units whose performance period ends December 31, 2008.

In addition to the benefits described above, upon retirement, the executive officers will be entitled to receive the retirement benefits described in the Pension Benefits table on page 26 and the nonqualified deferred compensation benefits set forth in the Nonqualified Deferred Compensation table on page 28 as well as lifetime retiree medical benefits if they were hired prior to February 1, 2000 and noncontributory lifetime retiree life insurance at 60% of pre-retirement levels but not more than $20,000 or less than $10,000.

SECURITY OWNERSHIP

The following table shows the number of shares of the Company s Common Stock beneficially owned on March 1, 2007, by each Director, by each of the Executive Officers named in the Summary Compensation Table on page 23, 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	61,338	S.E. Moore	1,016,695
Luke R. Corbett	42,724	P.B. Delaney	202,659
William E. Durrett	4,360	J.R. Hatfield	39,474
John D. Groendyke	35,349	D.P. Harris	28,882
Robert Kelley	49,960	S.R. Gerdes	15,274
Linda Petree Lambert	5,110	All Executive Officers and Directors as a group (25 persons)	1,725,772
Robert O. Lorenz	8,284		
Ronald H. White, M.D.	48,294		
J.D. Williams	27,771		

own include shares for which, in certain instances, an individual has disclaimed beneficial interest. Amounts shown for executive officers include 1,303,063 shares of

rs Deferred Compensation Plan.

100 shares; Mr. Durrett, Mr. Groendyke, Mr. Lorenz and Ms. Lambert, 0 shares; Mr. Moore, 865,200 shares; Mr. Delaney, 172,100 shares; Mr. Hatfield,14,068 share

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.

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)	1,485,602	$21.90	1,794,946(2)
Equity Compensation Plans Not Approved by			

Shareowners	0	N/A	N/A

ncentive Plan, which was approved by shareowners at the 1998 annual meeting, and the OGE Energy Corp. 2003 Stock Incentive Plan, which was approved by share
3 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. To our knowledge, all of our officers and directors subject to such reporting obligations satisfied their reporting obligations in full in 2006.

SHAREOWNER PROPOSALS

Any shareowner proposal intended to be included in the proxy statement for the Annual Meeting in 2008 must be received by the Company on or before November 30, 2007. 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 2008 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 Summary 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 Summary 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 Summary 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 Summary 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 Summary 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.

OGE Energy Corp.

2006 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. OG&E is the largest electric utility in Oklahoma and its franchised service territory includes the Fort Smith, Arkansas area. OG&E sold its retail 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 May 2006, Enogex Gas Gathering, L.L.C. (Gathering), a wholly-owned subsidiary of Enogex Inc., sold certain gas gathering assets in the Kinta, Oklahoma, area, which have been reported as discontinued operations in the Company s Consolidated Financial Statements (see Results of Operations Enogex Discontinued Operations for a further discussion). In December 2006, Enogex entered into a joint venture arrangement with a third party. The joint venture, Atoka Midstream LLC, intends to construct, own and operate a gathering system and processing plant and related facilities relating to production in certain areas in southeastern Oklahoma. Enogex holds its 50 percent membership interest in Atoka Midstream LLC through Enogex Atoka LLC (Enogex Atoka), a wholly-owned subsidiary of Enogex Inc. Enogex Atoka will act as the managing member and operator of the facilities owned by the joint venture.

Executive Overview

The Company s vision is to be a regional utility-focused energy business recognized for operational excellence and strong financial performance. The Company intends to execute its vision by focusing on its regulated electric utility business and unregulated midstream gas business. 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, maintenance of a dividend payout ratio consistent with its peer group, maintenance of strong credit ratings and appropriate returns on invested capital. The Company believes it can accomplish these financial goals by, among other things, pursuing multiple avenues to build its business, maintaining a diversified asset position, continuing to develop a wide range of skills to succeed with changes in its industries, providing products and services to customers efficiently, managing risks effectively and maintaining strong regulatory and legislative relationships.

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, replace aging transmission and distribution system and deploy newer technology that improves operational, financial and environmental performance. As part of this plan, OG&E purchased, for approximately $160 million, 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 this investment. Also, as part of this plan, on February 20, 2006, OG&E entered into an agreement to engineer, procure and construct a wind generation energy system for a 120 MW wind farm (Centennial) in northwestern Oklahoma. The wind farm was fully in service in January 2007. Through December 31, 2006, OG&E has spent approximately $171.1 million related to the Centennial wind farm. On January 17, 2007, OG&E sent notice to the OCC to trigger the Centennial wind farm rider for the first billing cycle in February 2007. OG&E has announced a six-year construction initiative that is estimated to include up to $3.3 billion in major projects designed to expand capacity, enhance reliability and improve environmental performance. The first part of this initiative involved OG&E entering into an agreement for the proposed construction of a 950 MW coal unit at OG&E s existing Sooner plant location near Red Rock, Oklahoma. OG&E expects construction to begin in 2007 and is targeting the completion of the power plant in the 2011/2012 timeframe. OG&E s share of the projected $1.8 billion construction cost for the plant will be about $759 million. OG&E s

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six-year construction initiative also includes strengthening and expanding the electric transmission, distribution and substation systems and replacing aging infrastructure. Other projects involve installing new emission-control equipment at existing OG&E power plants to help meet OG&E s commitment to meet environmental requirements. OG&E also expects to incur a significant amount of capital and operating expenditures in the next several years to comply with current and future environmental laws and regulations. For additional information regarding the above items and other regulatory matters, see Note 18 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. In August 2006, Enogex completed a project to expand its gathering pipeline capacity on the west side of its system in western Oklahoma and the Texas Panhandle that should enable Enogex to benefit from growth opportunities in that marketplace. Enogex continues to consider additional opportunities to expand this project. In addition to focusing on growing its earnings, Enogex has reduced its exposure to changes in commodity prices and minimized its exposure to keep-whole processing arrangements. Enogex s profitability increased significantly from 2003 to 2006 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, while at the same time decreasing the volatility associated with commodity prices. 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, Enogex s marketing business utilizes a strategy that seeks to minimize the amount of capital employed and to complement better the natural gas pipeline business. The Company expects to continue to pursue a disciplined approach to continuous improvement and efficiency of operations. Also, during 2005 and 2006, Enogex sold its interests in Enogex Arkansas Pipeline Corporation (EAPC) and Enerven Compression Services, LLC (Enerven) and certain gas gathering assets in the Kinta, Oklahoma area (the Kinta Assets) and will continue to review its asset portfolio and seek to divest underperforming or non-strategic assets. Also, on December 15, 2006, Enogex announced that it had entered into a firm capacity lease agreement with Midcontinent Express Pipeline, LLC for a primary term of 10 years (subject to possible extensions) for certain capacity on the Enogex system. The leased capacity provided for in this agreement is up to 0.5 billion cubic feet (Bcf) per day and is dependent on the shipper volumes that commit to the project. The Enogex capacity will be part of the proposed Midcontinent Express Pipeline (MEP), a joint venture between Kinder Morgan Energy Partners, L.P. and Energy Transfer Partners, L.P. In addition to the Enogex leased capacity, the proposed MEP project includes a new pipeline originating near Bennington, Oklahoma and terminating in Butler, Alabama. Pending necessary regulatory approval, the MEP pipeline project is currently expected to be in service by February 2009. Depending on the final capacity that MEP subscribes to pursuant to the agreement, Enogex expects its revenues from this firm capacity lease agreement to be between $12 million and $30 million annually. Enogex currently estimates that its capital expenditures related to this project during the next two to three years could be approximately $100 million. The Enogex lease agreement with the MEP is subject to certain contingencies including regulatory approval. Prior to such approval, Enogex may incur expenditures of between approximately $20 million and $40 million with the majority being for certain commitments for materials that can be sold or used in normal operations in the event the MEP project does not proceed and the amount not recovered or utilized for such expenditures is not expected to be material. Enogex also is seeking to provide lease capacity to Boardwalk s Gulf Crossings project. Boardwalk Pipeline Partners, LP, has announced plans to build the Gulf Crossings pipeline, which includes 355 miles of new interstate natural gas pipeline. It initially is expected to transport gas from the supply areas in Sherman, Texas, Bennington, Oklahoma and Paris, Texas to the Perryville, Louisiana Hub. Subject to regulatory approvals, the Gulf Crossings project is expected to be in service during the fourth quarter of 2008.

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 continue to focus on those products and services with limited or manageable commodity exposure. 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.

In December 2006, the Company and OG&E increased their aggregate available borrowing capacity under their revolving credit agreements from $750.0 million to $1.0 billion, $600 million for the Company and $400 million for OG&E. Each of the credit facilities has a five-year term with an option to extend the term for two additional one-year periods. Also, each of these credit facilities has an additional option at the end of the two renewal options to convert the outstanding balance to a one-year term loan. 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.

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Overview

Summary of Operating Results

2006 compared to 2005. The Company reported net income of approximately $262.1 million, or $2.84 per diluted share, in 2006 as compared to approximately $211.0 million, or $2.32 per diluted share, in 2005. The increase in net income during 2006 as compared to 2005 was primarily due to:

- OG&E reported net income of approximately $149.3 million, or $1.62 per diluted share of the Company s common stock, in 2006 as compared to approximately $129.7 million, or $1.43 per diluted share, in 2005;
- Enogex s operations, including discontinued operations, reported net income of approximately $113.5 million, or $1.23 per diluted share of the Company s common stock (of which $0.39 per diluted share was attributable to discontinued operations), in 2006 as compared to approximately $89.8 million, or $0.99 per diluted share (of which $0.55 per diluted share was attributable to discontinued operations) in 2005; and
- a net loss at the holding company of approximately $0.7 million, or $0.01 per diluted share, in 2006 as compared to a net loss of approximately $8.5 million, or $0.10 per diluted share, in 2005 primarily due to higher income tax benefits in 2006 as a result of recording the Employee Stock Ownership Plan (ESOP) dividend deduction at the holding company in 2006 which was previously recorded at OG&E in 2005.

2005 compared to 2004. The Company reported net income of approximately $211.0 million, or $2.32 per diluted share, in 2005 as compared to approximately $153.5 million, or $1.73 per diluted share, in 2004. 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, in 2005 as compared to approximately $107.6 million, or $1.22 per diluted share, in 2004;
- 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 (of which $0.55 per diluted share was attributable to discontinued operations), in 2005 as compared to approximately $60.7 million, or $0.69 per diluted share (of which $0.13 per diluted share was attributable to discontinued operations), in 2004; and
- a net loss at the holding company of approximately $8.5 million, or $0.10 per diluted share, in 2005 as compared to a net loss of approximately $14.8 million, or $0.18 per diluted share, in 2004 primarily due to lower interest expense of approximately $9.2 million in 2005 partially offset by a lower income tax benefit of approximately $3.8 million in 2005 due to a lower taxable loss in 2005.

Recent Developments

OG&E Wind Power Filing

As discussed above, in January 2007, the Centennial wind farm in northwestern Oklahoma was fully in service. Through December 31, 2006, OG&E has spent approximately $171.1 million related to the Centennial wind farm. The OCC previously had approved a settlement agreement approving the Centennial wind power contract and a recovery rider for up to $205 million in construction costs and allowance for funds used during construction. The settlement also indicated that OG&E shall file for a general rate review during 2009 that will permit the OCC to issue an order no later than December 31, 2009 placing the Centennial wind farm in OG&E s rate base. On January 17, 2007, OG&E sent notice to the OCC to trigger the Centennial wind farm rider for the first billing cycle in February 2007. The recovery rider is designed to recover approximately $22.6 million in the first year of operations, which amount will decline over the life of the facility. Because the wind farm rider was implemented in February 2007, OG&E expects to recover approximately $20.7 million under the rider during the remaining 11 months of 2007. OG&E expects the recovery rider to remain in effect through late 2009. As explained below, the recent rate order from the APSC allows for the recovery of the portion of the Centennial wind farm allocable to OG&E s customers in Arkansas.

OG&E Arkansas Rate Case Filing

On July 28, 2006, OG&E filed with the APSC an application for an annual rate increase of approximately $13.5 million to recover, among other things, its investment in, and the operating expenses of, the McClain Plant, the Centennial wind power project and the costs of electric system expansion and upgrades based on a return on equity of 11.75 percent. On November 29, 2006, OG&E reached a settlement with the other parties in this case for an annual rate increase of approximately $5.4 million. In the settlement agreement, the parties also agreed that OG&E would be allowed to recover the full Arkansas portion of the Centennial wind farm. On January 5, 2007, the APSC approved the settlement and issued a rate order that provides for a $5.4 million annual increase in OG&E s electric rates and a 10.0 percent return on equity. The new Arkansas rates became effective in February 2007.

Proposed Construction of Power Plant

As discussed above, OG&E has entered into a contract with American Electric Power s subsidiary, Public Service Company of Oklahoma (PSO), and the Oklahoma Municipal Power Authority (OMPA) to build a new 950 MW coal unit at OG&E s existing Sooner plant location near Red Rock, Oklahoma. The estimated $1.8 billion project is the result of PSO s December 2005 request for proposals in which it sought bids for up to 600 MW s of new base load generation to be available to PSO. The unit, to be called Red Rock, is expected to be one of the cleanest of its size using coal from the Powder River Basin, which is located near Gillette, Wyoming. OG&E will operate the facility and expects to spend approximately $759 million in construction costs related to its 42 percent ownership percentage in the project and approximately $30 million in transmission costs for the project. PSO will own 50 percent and the OMPA will own eight percent. On December 1, 2006, OG&E submitted an application to the Oklahoma Department of Environmental Quality (ODEQ) for an air permit for the Red Rock plant. OG&E is seeking to have the air permit approved by the ODEQ by August 1, 2007. OG&E expects construction to begin in 2007 and is targeting the completion of the power plant in the 2011/2012 timeframe. OG&E filed an application with the OCC on January 17, 2007 asking the OCC to find that its portion of the construction costs are prudent and that a recovery mechanism should be established to recover OG&E s overall cost of capital on the investment during the construction period. The OCC rules provide that the OCC has up to 240 days to issue an order determining OG&E s pre-approval request, however OG&E s application requested that the OCC issue an order by July 20, 2007. The project is contingent upon numerous factors, including the successful completion of contract negotiations and the necessary regulatory and environmental approvals. Under the construction, ownership and operating agreement between OG&E, PSO and the OMPA, the parties could incur up to $60 million (of which approximately $25 million would be borne by OG&E) prior to the receipt of acceptable regulatory approvals and permits. If such approvals and permits were not obtained and the Red Rock project was abandoned, the Company can provide no assurance that these expenditures incurred by OG&E would be recoverable in future rates.

Enogex Expansion Projects

In August 2006, Enogex completed a project to expand its gathering pipeline capacity on the west side of its system in western Oklahoma and the Texas Panhandle that should enable Enogex to benefit from growth opportunities in that marketplace. Enogex continues to consider additional opportunities to expand this project.

Termination of Continental Connector Project

Enogex had previously announced that it had entered into a letter of intent with El Paso Corporation (El Paso) relating to El Paso s Continental Connector Project. The letter of intent contemplated arrangements by which El Paso or an affiliate would execute a lease of capacity on the Enogex pipeline system and the leased Enogex pipeline capacity would become part of the Continental Connector Project. The letter of intent expired on April 28, 2006. In early October 2006, El Paso determined not to proceed with its proposed Continental Connector project. Enogex did not incur any material expenditures relating to this proposed project.

Oklahoma City Dayton Tire Plant Closing

In July 2006, the Boards of Directors of Bridgestone Firestone North American Tire and its parent company, Bridgestone Americas Holding Inc., approved the closing of the Oklahoma City Dayton tire plant, which closed in December 2006. The closing of this plant is expected to reduce net income by approximately $1.1 million, or $0.01 per diluted share, in 2007.

2007 Outlook

The Company previously disclosed in its Form 10-Q for the quarter ended September, 2006 that its 2007 earnings guidance was $213 million to $231 million of income from continuing operations, or $2.30 to $2.50 per diluted share. The Company has reaffirmed the 2007 earnings guidance, which excludes any gains on asset sales and assumes approximately 92.5 million average diluted shares outstanding and an effective tax rate of 32.6 percent. The Company is currently projecting earnings toward the lower half of the guidance due to refinements of its prior estimates based on its 2006 audited financial results and numerous other factors. At the utility, these factors include reduced tariffs for fuel-related costs, the slight delay in implementing the Centennial wind farm rider and increased depreciation expense, offset in part by higher anticipated margin growth. At Enogex, a key factor was the recognition of mark-to-market gains in the marketing business in the fourth quarter of 2006 that were previously anticipated for the first quarter of 2007. Projected cash flow from operations of between $371 million and $389 million for 2007 has been lowered to $336 million to $354 million primarily due to the collection by OG&E during 2006 under approved tariffs of approximately $26.7 million of additional fuel-related revenues that was not intended by the OCC rate order in December 2005. The $26.7 million, plus interest, will be credited to OG&E s Oklahoma customers in 2007 and 2008 through OG&E s automatic fuel adjustment clause and reduced tariffs were filed, effective December 31, 2006, that will cease the continued recovery of these additional fuel-related revenues. See Financial Condition below.

	Earnings guidance per 2006 10-K	
(In millions, except per share data)	Dollars	Diluted EPS
OG&E	$154 - $162	$1.67 - $1.75
Enogex	$63 - $72	$0.68 - $0.78
Holding Company	($3) - ($4)	($0.03) - ($0.05)
Total	$213 - $231	$2.30 - $2.50

Key assumptions for 2007 are:

As shown above, OG&E s earnings guidance has been reaffirmed at $154 million to $162 million. Key factors and assumptions underlying this guidance include:

OG&E

- Normal weather patterns are experienced for the year;
- Gross margin on revenues (gross margin) on weather-adjusted, retail electric sales increases approximately two percent;
- Centennial wind farm rider increase of approximately $21 million;
- Arkansas rate increase of approximately $5 million which began in February 2007;
- Operating expenses increase approximately $28 million primarily due to higher employee costs and higher depreciation;
- Interest costs increase approximately $7 million primarily due to higher levels of long-term and short-term debt;
- Tax credit of approximately $11 million associated with the Centennial wind farm; and
- Capital expenditures for investment in OG&E s generation, transmission and distribution system are approximately $427 million in 2007, which includes capital expenditures of up to $94 million associated with OG&E s Red Rock generating plant.

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

As shown above, Enogex s earnings guidance remains unchanged from $63 million to $72 million, or $0.68 to $0.78 per diluted share. Key factors and assumptions underlying this guidance include:

Total Enogex anticipated gross margin of approximately $312 million to $328 million as compared to approximately $307 million in 2006. The 2007 guidance includes:

Transportation and storage gross margin contribution of approximately $136 million. As compared to 2006, margins are projected to increase approximately $11 million primarily in the storage business as a result of new contracts and higher storage fees.

Gathering and processing gross margin contribution of approximately $168 million to $183 million as compared to approximately $168 million in 2006. Key factors affecting the gathering and processing gross margin are:

Gross margin decrease in Enogex s gathering and processing business in 2007 primarily due to lower commodity spreads offset by higher contractual gains as a result of higher natural gas prices;
Increase of 13 percent in volumes in Enogex s gathering business as compared to 2006 primarily due to new business;
Forecasted natural gas prices of $6.33 to $6.62 per Million British thermal unit (MMBtu) in 2007 as compared to $6.04 in 2006;
Forecasted commodity spreads of $2.69 to $3.21 per MMBtu in 2007 as compared to $3.99 per MMBtu assumed in 2006;
Forecasted average natural gas liquids prices of $0.93 to $1.02 per gallon in 2007 as compared to $1.10 per gallon in 2006; and
Enogex s gathering and processing business is projecting approximately 318 new well connects in 2007 including wells behind central receipt points.

Marketing gross margin contribution of approximately $9 million in 2007 as compared to approximately $14 million in 2006 primarily due to the recognition of mark-to-market hedging gains in 2006.

Operating expenses increase approximately $16 million primarily due to increased employee costs associated with new business growth and higher depreciation costs;
Other income decreases approximately $16 million from 2006 as a result of lower interest income due to the redeployment of cash from assets sales and the result of a legal settlement received in 2006;
Interest expense remains relatively flat in 2007; and

Capital expenditures for investment in Enogex s pipeline system are approximately $125 million in 2007.

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 2007 earnings guidance.

Holding Company

As shown above, the projected loss at the holding company is $3 million to $4 million, or $0.03 to $0.05 per diluted share, primarily due to projected interest costs.

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 no more than 65 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. At the Company s November 2006 Board meeting, management, after considering estimates of future earnings and numerous other factors, recommended to the Board of Directors an increase in the current quarterly dividend rate to $0.34 per share from $0.3325 per share payable in the first quarter of 2007.

Results of Operations

The following discussion and analysis presents factors that affected the Company s consolidated results of operations for the years ended December 31, 2006, 2005 and 2004 and the Company s consolidated financial position at December 31, 2006 and 2005. 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.

Year ended December 31 *(In millions, except per share data)*	**2006**	2005	2004
Operating income	**$ 432.7**	$ 322.4	$ 294.5
Net income	**$ 262.1**	$ 211.0	$ 153.5
Basic average common shares outstanding	**91.0**	90.3	88.0
Diluted average common shares outstanding	**92.1**	90.8	88.5
Basic earnings per average common share	**$ 2.88**	$ 2.34	$ 1.74
Diluted earnings per average common share	**$ 2.84**	$ 2.32	$ 1.73
Dividends declared per share	**$ 1.3375**	$ 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

Year ended December 31 *(In millions)*	**2006**	2005	2004
OG&E (Electric Utility)	**$ 293.9**	$ 232.2	$ 192.3
Enogex (Natural Gas Pipeline)	**138.8**	89.6	103.3
Other Operations (A)	**---**	0.6	(1.1)
Consolidated operating income	**$ 432.7**	$ 322.4	$ 294.5

(A) 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.

OG&E

Year ended December 31 *(Dollars in millions)*	**2006**	2005	2004
Operating revenues	**$ 1,745.7**	$ 1,720.7	$ 1,578.1
Cost of goods sold	**950.0**	994.2	914.2
Gross margin on revenues	**795.7**	726.5	663.9
Other operation and maintenance	**316.5**	309.2	301.9
Depreciation	**132.2**	134.4	122.7
Taxes other than income	**53.1**	50.7	47.0
Operating income	**293.9**	232.2	192.3
Interest income	**1.9**	2.6	2.7
Allowance for equity funds used during construction	**4.1**	---	0.9
Other income (loss)	**4.0**	(2.8)	4.5
Other expense	**9.7**	2.5	2.3
Interest expense	**60.1**	47.2	37.5
Income tax expense	**84.8**	52.6	53.0
Net income	**$ 149.3**	$ 129.7	$ 107.6
Operating revenues by classification			
Residential	**$ 698.8**	$ 663.6	$ 611.4
Commercial	**428.3**	418.9	389.9
Industrial	**345.0**	355.6	326.7
Public authorities	**171.0**	173.1	158.5
Sales for resale	**65.4**	67.7	57.0
Provision for rate refund	**(0.9)**	(2.0)	(6.9)
System sales revenues	**1,707.6**	1,676.9	1,536.6
Off-system sales revenues	**2.7**	4.9	0.8
Other	**35.4**	38.9	40.7
Total operating revenues	**$ 1,745.7**	$ 1,720.7	$ 1,578.1
MWH (A) sales by classification (in millions)			
Residential	**8.7**	8.5	7.9
Commercial	**6.2**	6.0	5.7
Industrial	**7.1**	7.2	7.0
Public authorities	**2.9**	2.8	2.7
Sales for resale	**1.5**	1.5	1.4
System sales	**26.4**	26.0	24.7
Off-system sales	**---**	0.1	0.1
Total sales	**26.4**	26.1	24.8
Number of customers	**754,840**	745,493	735,008
Average cost of energy per KWH (B) - cents			
Fuel	**3.040**	3.011	2.887
Fuel and purchased power	**3.398**	3.300	3.436
Degree days (C)			
Heating			
Actual	**2,746**	3,159	3,114
Normal	**3,631**	3,631	3,650
Cooling			
Actual	**2,485**	2,163	1,839
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 a

2006 compared to 2005. OG&E s operating income increased approximately $61.7 million or 26.7 percent in 2006 as compared to 2005 primarily due to higher gross margins partially offset by higher operating expenses.

Gross margin, which is operating revenues less cost of goods sold, was approximately $795.7 million in 2006 as compared to approximately $726.5 million in 2005, an increase of approximately $69.2 million, or 9.5 percent. The gross margin increased primarily due to:

- price variance primarily due to rate increases authorized in the OCC order in December 2005, which increased the gross margin by approximately $47.6 million;
- new customer growth in OG&E s service territory, which increased the gross margin by approximately $10.9 million;
- increased peak demand by industrial customers in OG&E s service territory, which increased the gross margin by approximately $6.7 million; and
- warmer weather in OG&E s service territory, which increased the gross margin by approximately $6.2 million.

Cost of goods sold for OG&E consists of fuel used in electric generation and purchased power. Fuel expense was approximately $730.3 million in 2006 as compared to approximately $795.4 million in 2005, a decrease of approximately $65.1 million or 8.2 percent due to lower natural gas prices. OG&E s electric generating capability is fairly evenly divided between coal and natural gas and provides for flexibility to use either fuel to the best economic advantage for OG&E and its customers. In 2006 and 2005, respectively, OG&E s fuel mix was 67 percent coal and 33 percent natural gas and 70 percent coal and 30 percent natural gas. Though OG&E has a higher installed capability of generation from natural gas units of 57 percent, it has been more economical to generate electricity for our customers with lower priced coal. Purchased power costs were approximately $219.7 million in 2006 as compared to approximately $198.8 million in 2005, an increase of approximately $20.9 million or 10.5 percent. This increase was primarily due to a power purchase contract that allowed OG&E to make economic purchases during peak demand summer months.

Other operating and maintenance expenses were approximately $316.5 million in 2006 as compared to approximately $309.2 million in 2005, 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 and other employee benefits of approximately $12.5 million;
- higher allocations from the holding company of approximately $3.9 million primarily due to an increase in incentive compensation;
- higher bad debt expense of approximately $3.5 million; and
- an additional accrual of approximately $2.2 million for the settlement of a claim.

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

- a decrease in outside services of approximately $9.3 million; and
- an increase in capitalized work of approximately $6.4 million primarily due to increased labor and transportation expenses related to more capital projects in 2006.

The other operating and maintenance expense variance includes other operating and maintenance expenses associated with the acquisition of the McClain Plant, which expenses ceased being recorded as a regulatory asset on July 8, 2005.

Depreciation expense was approximately $132.2 million in 2006 as compared to approximately $134.4 million in 2005, a decrease of approximately $2.2 million or 1.6 percent. The decrease in depreciation expense was primarily due to:

- a decrease in depreciation rates that was implemented January 1, 2006 as approved by the OCC in December 2005; and
- a decrease due to the retirement of assets at June 30, 2006 related to a power supply contract with a large industrial customer that expired June 1, 2006.

These decreases in depreciation expense were partially offset by a full year of depreciation expense in 2006 associated with the acquisition of the McClain Plant.

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Taxes other than income were approximately $53.1 million in 2006 as compared to approximately $50.7 million in 2005, an increase of approximately $2.4 million or 4.7 percent, primarily due to increased ad valorem taxes. This variance includes ad valorem taxes associated with the acquisition of the McClain Plant, which expenses ceased being recorded as a regulatory asset on July 8, 2005.

Allowance for equity funds used during construction was approximately $4.1 million in 2006 due to construction costs associated with OG&E s Centennial wind farm that exceeded the average daily short-term borrowings in 2006. There was no allowance for equity funds used during construction in 2005.

Other income includes, among other things, contract work performed, non-operating rental income and miscellaneous non-operating income. Other income was approximately $4.0 million in 2006 as compared to a reduction in other income of approximately $2.8 million in 2005, an increase in other income of approximately $6.8 million. The increase in other income was primarily due to:

- a gain of approximately $3.5 million from the sale of miscellaneous assets that were recorded in 2004 and were reclassified to a regulatory liability in 2005; and
- the benefit associated with the tax gross-up of approximately $4.1 million of allowance for equity funds used during construction.

Other expense includes, among other things, expenses from losses on the sale and retirement of assets, miscellaneous charitable donations, expenditures for certain civic, political and related activities and miscellaneous deductions and expenses. Other expense was approximately $9.7 million in 2006 as compared to approximately $2.5 million in 2005, an increase of approximately $7.2 million primarily due to a loss on the retirement of fixed assets of approximately $6.0 million.

Interest expense was approximately $60.1 million in 2006 as compared to approximately $47.2 million in 2005, an increase of approximately $12.9 million or 27.3 percent. The increase in interest expense was primarily due to:

- increased interest of approximately $7.7 million due to the one-time recognition of interest expense associated with a certain water storage agreement;
- increased interest of approximately $4.8 million on debt associated with the McClain Plant acquisition, which OG&E ceased recording as a regulatory asset on July 8, 2005;
- increased interest of approximately $3.0 million due to the termination of an interest rate swap in 2005; and
- increased interest of approximately $1.5 million due to increased borrowings from the holding company to cover increased construction costs.

These increases in interest expense were partially offset by:

- a decrease in interest expense due to an increase in the allowance for borrowed funds used during construction of approximately $2.3 million; and
- a decrease in interest expense of approximately $1.9 million related to the Company making a deposit with the Internal Revenue Service (IRS) in August 2006 in anticipation that a portion of prior year deductions will be disallowed, which enabled OG&E to cease accruing interest in August 2006.

Income tax expense was approximately $84.8 million in 2006 as compared to approximately $52.6 million in 2005, an increase of approximately $32.2 million or 61.2 percent. The increase in income tax expense was primarily due to:

higher pre-tax income for OG&E;

the ESOP dividend deduction at the holding company in 2006 which was previously recorded at OG&E in 2005 of approximately $7.4 million; and
a decrease in state tax credits in 2006 of approximately $3.8 million.

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

Gross margin 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.

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.

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 were 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.

There was a reduction in other income of approximately $2.8 million in 2005 as compared to income of approximately $4.5 million in 2004, a decrease of approximately $7.3 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.

Interest expense was approximately $47.2 million in 2005 as compared to approximately $37.5 million in 2004, an increase of approximately $9.7 million or 25.9 percent. The increase in interest expense was primarily due to:

- increased interest 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;

increased interest 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
increased interest of approximately $3.3 million for additional interest expense related to income taxes as a result of new guidelines issued by the IRS related to a change in the method of accounting used to capitalize costs for self-construction for income tax purposes only.

These increases in 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 decrease 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.

Enogex Continuing Operations

Year ended December 31 *(Dollars in millions)*	**2006**	2005	2004
Operating revenues	**$ 2,367.8**	$ 4,332.4	$ 3,379.9
Cost of goods sold	**2,060.4**	4,090.4	3,118.2
Gross margin on revenues	**307.4**	242.0	261.7
Other operation and maintenance	**110.0**	96.6	93.5
Depreciation	**42.3**	40.4	41.1
Impairment of assets	**0.3**	---	7.8
Taxes other than income	**16.0**	15.4	16.0
Operating income	**138.8**	89.6	103.3
Interest income	**11.1**	2.9	3.2
Other income	**7.7**	0.8	4.5
Other expense	**0.3**	0.3	0.3
Interest expense	**31.8**	32.6	32.2
Income tax expense	**48.0**	20.4	29.4
Income from continuing operations	**$ 77.5**	$ 40.0	$ 49.1
New well connects (A)	**206**	223	192
Gathered volumes TBtu/d (B)	**0.98**	0.92	0.84
Incremental transportation volumes TBtu/d	**0.46**	0.39	0.39
Total throughput volumes TBtu/d	**1.44**	1.31	1.23
Natural gas processed TBtu/d	**0.54**	0.52	0.50
Natural gas liquids sold (keep-whole) million gallons	**244**	219	185
Natural gas liquids sold (purchased for resale) million gallons	**113**	77	78
Natural gas liquids sold (percentage of liquids) million gallons	**14**	15	16
Total natural gas liquids sold million gallons	**371**	311	279
Average sales price per gallon	**$ 0.901**	$ 0.847	$ 0.720

(A) Excludes wells behind central receipt points.

(B) Trillion British thermal units per day.

2006 compared to 2005. Enogex s operating revenues and cost of goods sold decreased in 2006 approximately $2.0 billion, or 45.4 percent, and $2.0 billion, or 49.6 percent, respectively, as compared to 2005 primarily due to a lower level of trading activity due to a shift in strategy in Enogex s marketing business. Enogex s operating income increased approximately $49.2 million in 2006 as compared to 2005 primarily due to increased gross margins in each of Enogex s businesses largely as a result of higher commodity spreads and business growth in 2006 as compared to 2005. The increases in gross margin were partially offset by higher operating and maintenance expenses.

Transportation and storage contributed approximately $125.6 million of Enogex s gross margin in 2006 as compared to approximately $99.1 million in 2005, an increase of approximately $26.5 million or 26.7 percent. The gross margin increased primarily due to:

- better management of gas pipeline imbalances as Enogex reduced its exposure to gas imbalances while taking advantage of favorable market price movement in 2006 and gas imbalance expense recognized by the gathering business in 2006 (previously carried by the transportation and storage business in 2005), which increased the gross margin by approximately $11.5 million in 2006;
- increased commodity, interruptible and low and high pressure revenues primarily due to higher volumes, which increased the gross margin by approximately $6.2 million;
- a change in Enogex s 2005 accounting estimate of the volume of natural gas in its natural gas storage inventory, which reduced the 2005 gross margin by approximately $5.7 million;
- improved recovery of fuel as the Company transitioned to zonal fuel factors in 2006, which increased the gross margin by approximately $4.7 million;
- storage field hedging gains, which increased the gross margin by approximately $3.5 million; and
- increased natural gas sales due to higher realized natural gas prices in 2006, which increased the gross margin by approximately $3.5 million.

These increases in the transportation and storage gross margin were partially offset by a lower of cost or market adjustment related to natural gas inventory used to operate the pipeline during 2006, which reduced the 2006 gross margin by approximately $8.3 million as there was no comparable item during 2005.

Gathering and processing contributed approximately $167.6 million of Enogex s gross margin in 2006 as compared to approximately $140.2 million in 2005, an increase of approximately $27.4 million or 19.5 percent. The gathering and processing gross margin increased primarily due to:

- increased net keep-whole margins primarily due to higher commodity spreads in 2006 as compared to 2005 and increased volumes due to business growth, which increased the gross margin by approximately $33.5 million;
- contractual fuel gains primarily due to higher natural gas prices in 2006, which increased the gross margin by approximately $4.9 million; and
- a reduction in the Company s over recovered position as the Company transitioned to zonal fuel rates in 2006, which increased the gross margin by approximately $2.5 million.

These increases in the gathering and processing gross margin were partially offset by the recognition of imbalance expense in 2006 (previously carried by the transportation and storage business in 2005), which reduced the gross margin by approximately $13.8 million in 2006.

Marketing contributed approximately $14.2 million of Enogex s gross margin in 2006 as compared to approximately $2.7 million in 2005, an increase of approximately $11.5 million. The gross margin increased primarily due to:

- gains in storage activity due to timing, resulting from recording Enogex s storage hedges at market value at December 31, 2006 and an increase in storage capacity, which increased the gross margin by approximately $13.2 million;

- a correction to the accounting procedure for park and loan transactions (natural gas storage transactions) in the first quarter of 2005, which decreased the gross margin in the first quarter of 2005 by approximately $7.7 million (see Note 16 of Notes to Consolidated Financial Statements); and
- more favorable market conditions on transportation contracts, which increased the gross margin by approximately $7.6 million.

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

- a lower of cost or market adjustment related to natural gas in storage during 2006, which reduced the 2006 gross margin by approximately $9.9 million; and

- lower gains in trading and park and loan activity due to a lower level of activity in Enogex s marketing business and less favorable market conditions, which reduced the gross margin by approximately $6.0 million.

Enogex s other operating and maintenance expenses were approximately $110.0 million in 2006 as compared to approximately $96.6 million in 2005, an increase of approximately $13.4 million or 13.9 percent. The increase in other operating and maintenance expenses was primarily due to:

- higher salaries, wages and other employee benefits of approximately $9.5 million primarily due to incentive compensation and hiring additional employees to support business growth; and
- higher materials and supplies costs of approximately $2.7 million primarily related to work performed to maintain the integrity and safety of Enogex s pipeline, higher cost of materials and increased materials used at newly added facilities.

These increases in other operating and maintenance expenses were partially offset by a sales and use tax refund of approximately $2.0 million received in May 2006 related to activity in prior years.

Depreciation expense was approximately $42.3 million in 2006 as compared to approximately $40.4 million during the same period in 2005, an increase of approximately $1.9 million or 4.7 percent, primarily due to new assets placed into service during 2006.

Interest income was approximately $11.1 million in 2006 as compared to approximately $2.9 million in 2005, an increase of approximately $8.2 million primarily due to interest income on cash investments from interest earned on the cash proceeds from the sale of EAPC in October 2005 and the sale of the Kinta Assets in May 2006.

Other income was approximately $7.7 million in 2006 as compared to approximately $0.8 million in 2005, an increase of approximately $6.9 million. The increase in other income was primarily due to:

- a litigation settlement of approximately $5.2 million (see Note 17 of Notes to Consolidated Financial Statements) in 2006;
- a gain of approximately $1.0 million in the fourth quarter of 2006 from the sale of certain west Texas pipeline asset segments; and
- a gain of approximately $0.5 million in the first quarter of 2006 from the sale of small gathering sections of Enogex s pipeline.

Income tax expense was approximately $48.0 million in 2006 as compared to approximately $20.4 million in 2005, an increase of approximately $27.6 million primarily due to higher pre-tax income for Enogex.

For 2006, Enogex s net income, including the discontinued operations discussed below under the caption Enogex Discontinued Operations, was approximately $113.5 million. During 2006, Enogex had an increase in net income of approximately $41.2 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 the Kinta Assets in May 2006 of approximately $34.1 million;
- litigation settlement (see Note 17 of Notes to Consolidated Financial Statements) of approximately $3.2 million;

income from discontinued operations of approximately $1.9 million;

a sales and use tax refund related to activity in prior years of approximately $1.3 million;

the sale of certain west Texas pipeline asset segments of approximately $0.6 million; and

the sale of small gathering sections of Enogex s pipeline of approximately $0.3 million.

These increases in net income were partially offset by a decrease in net income of approximately $0.2 million related to the impairment of certain long-lived assets.

For 2005, Enogex s net income, including the discontinued operations discussed below under the caption Enogex Discontinued Operations, was approximately $89.8 million. During 2005, Enogex had an increase in net income of approximately $45.3 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 $11.3 million;

a gain on the sale of Enerven in August 2005 of approximately $1.8 million; and

income from a sales tax refund related to activity in prior years of approximately $0.2 million.

These increases to net income were partially offset by a correction to the accounting procedure for park and loan transactions in 2005 of approximately $4.7 million.

2005 compared to 2004. Enogex s operating income decreased approximately $13.7 million in 2005 as compared to 2004 primarily due to decreased gross margins in Enogex s marketing business and Enogex s transportation and storage business, which were partially offset by increased gross margins in Enogex s gathering and processing business. The overall decrease in gross margins was 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 $140.2 million of Enogex s gross margin in 2005 as compared to approximately $123.4 million in 2004, an increase of approximately $16.8 million or 13.6 percent. The gathering and processing 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 $7.2 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 $6.2 million;

increased condensate margins primarily due to higher condensate prices, which increased the gross margin by approximately $3.0 million;

higher volumes related to compression and dehydration, which increased the gross margin by approximately $2.5 million;

higher volumes on the low pressure gathering systems, which increased the gross margin by approximately $2.2 million;

- increased percent of liquids margins primarily due to higher natural gas prices, which increased the gross margin by approximately $1.4 million; and
- higher margin on natural gas sales reflective of opportunities in the marketplace, which increased the gross margin by approximately $1.1 million.

These increases in the gathering and 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 $3.2 million;

- 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 $1.0 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 88.7 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 the first quarter of 2005, which reduced the gross margin by approximately $7.7 million (see Note 16 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 $96.6 million in 2005 as compared to approximately $93.5 million in 2004, an increase of approximately $3.1 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 $4.4 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.

Interest income was approximately $2.9 million in 2005 as compared to approximately $3.2 million in 2004, a decrease of approximately $0.3 million or 9.4 percent, primarily due to a decrease in interest income of approximately $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 in interest income of approximately $1.1 million from parent due to funds received from the sale of EAPC in October 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.

Income tax expense was approximately $20.4 million in 2005 as compared to approximately $29.4 million in 2004, a decrease of approximately $9.0 million or 30.6 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 $89.8 million. During 2005, Enogex had an increase in net income of approximately $45.3 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 $11.3 million;
- a gain on the sale of Enerven in August 2005 of approximately $1.8 million; and
- income from a sales tax refund related to activity in prior years of approximately $0.2 million.

These increases to net income were partially offset by a correction to the accounting procedure for park and loan transactions in 2005 of approximately $4.7 million.

For 2004, Enogex s net income, including the discontinued operations discussed below under the caption Enogex Discontinued Operations, was approximately $60.7 million. During 2004, Enogex had an increase in net income of approximately $15.6 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 $11.7 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.

Enogex Discontinued Operations

In April 2005, Enogex Compression Company, LLC (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 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 a 75 percent interest in the NOARK Pipeline System Limited Partnership. This sale was completed on October 31, 2005. The Company received approximately $177.4 million in cash proceeds and recognized an after tax gain of approximately $36.7 million from the sale of this business in the fourth quarter of 2005. 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, was used, among other things, to reduce short-term debt levels and fund capital expenditures.

In March 2006, Enogex announced that its wholly-owned subsidiary, Gathering, had entered into an agreement to sell certain gas gathering assets in the Kinta, Oklahoma, area. The Gathering assets included in the transaction were approximately 568 miles of gas gathering pipeline and 22 compressor units with current volumes of approximately 145 million cubic feet per day, all in eastern Oklahoma. The sale price was approximately $93 million. This transaction closed on May 1, 2006 and Enogex recorded an after tax gain of approximately $34.1 million during the second quarter of 2006. The proceeds from the sale, were used, among other things, to reduce short-term debt levels and fund capital expenditures.

As a result of these sale transactions, Enogex Compression s interest in Enerven, Enogex s interest in EAPC and Gathering s Kinta Assets, which were part of the Natural Gas Pipeline segment, have been reported as discontinued operations for the years ended December 31, 2006, 2005 and 2004 in the Consolidated Financial Statements. Enogex Compression s sale of its Enerven interest and Enogex s sale of its EAPC interest were completed during 2005 and, therefore, there are no results of operations for these transactions during 2006. Results for these discontinued operations are summarized and discussed below.

Year ended December 31 *(In millions)*	**2006**	2005	2004
Operating revenues	**$ 9.4**	$ 106.0	$ 120.1
Cost of goods sold	**4.9**	69.5	80.0
Gross margin on revenues	**4.5**	36.5	40.1
Other operation and maintenance	**1.0**	7.5	7.9
Depreciation	**0.3**	5.8	6.5
Taxes other than income	**0.1**	1.3	1.5
Operating income	**3.1**	21.9	24.2
Interest income	**---**	0.1	0.3
Other income	**56.0**	66.2	---
Other expense	**---**	0.2	0.6
Interest expense	**---**	4.0	5.3
Income tax expense	**23.1**	34.4	7.0
Net income	**$ 36.0**	$ 49.8	$ 11.6

2006 compared to 2005. Gross margin decreased approximately $32.0 million or 87.7 percent in 2006 as compared to 2005 primarily due to the sale of EAPC in October 2005, the sale of the Kinta Assets in May 2006 and a decrease in natural gas purchases and sales due to a decrease in natural gas transported prior to these assets being sold.

Operating and maintenance expense decreased approximately $6.5 million or 86.7 percent in 2006 as compared to 2005 primarily due to the sale of EAPC in October 2005 and the sale of the Kinta Assets in May 2006.

Depreciation expense decreased approximately $5.5 million or 94.8 percent in 2006 as compared to 2005 primarily due to the sale of EAPC in October 2005 and ceasing depreciation expense in January 2006 when the Kinta Assets were reported as a discontinued operation.

Taxes other than income decreased approximately $1.2 million or 92.3 percent in 2006 as compared to 2005 for ad valorem taxes primarily due to the sale of EAPC in October 2005.

Other income decreased approximately $10.2 million or 15.4 percent in 2006 as compared to 2005 due to the sale of the Kinta Assets in May 2006 partially offset by the sale of EAPC in October 2005 and the sale of Enerven in August 2005.

Interest expense decreased approximately $4.0 million or 100.0 percent in 2006 as compared to 2005 due to the sale of EAPC in October 2005 and the use of a portion of the sale proceeds to repay EAPC long-term debt.

Income tax expense increased approximately $11.3 million or 32.8 percent in 2006 as compared to 2005 primarily due to the sale of the Kinta Assets in May 2006 partially offset by the sale of EAPC in October 2005 and the sale of Enerven in August 2005.

2005 compared to 2004. Gross margin decreased approximately $3.6 million or 9.0 percent in 2005 as compared to 2004 primarily due to the sale of EAPC in October 2005 and a decrease in natural gas purchases and sales due to a decrease in natural gas transported prior to these assets being sold.

Other income increased approximately $66.2 million in 2005 as compared to 2004 due to a pre-tax gain of approximately $83.4 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.

Interest expense decreased approximately $1.3 million or 24.5 percent in 2005 as compared to 2004 due to the sale of EAPC in October 2005 and the use of a portion of the sale proceeds to repay EAPC long-term debt.

Income tax expense increased approximately $27.4 million in 2005 as compared to 2004 primarily due to the sale of the Kinta Assets in May 2006 partially offset by the sale of EAPC in October 2005 and the sale of Enerven in August 2005.

Financial Condition

The balance of Cash and Cash Equivalents was approximately $47.9 million and $26.4 million at December 31, 2006 and 2005, respectively, an increase of approximately $21.5 million or 81.4 percent, primarily due to proceeds received in October 2006 from the sale of Gathering s Kinta Assets in May 2006.

The balance of Funds on Deposit was approximately $32.0 million at December 31, 2006 due to the Company making a deposit with the IRS on August 17, 2006 in anticipation that a portion of prior year deductions will be disallowed. The deposit enabled the Company to cease accruing interest effective August 17, 2006. See Note 10 of Notes to Consolidated Financial Statements for a further discussion.

The balance of Accounts Receivable, Net was approximately $344.3 million and $591.4 million at December 31, 2006 and 2005, respectively, a decrease of approximately $247.1 million or 41.8 percent, primarily due to lower natural gas sales prices and volumes by Enogex, a decrease in OG&E s billings to its customers reflecting lower fuel costs in December 2006 as compared to December 2005 and payments received from other utilities for OG&E s assistance with hurricanes Katrina and Rita.

The balance of current Price Risk Management assets was approximately $41.9 million and $116.5 million at December 31, 2006 and 2005, respectively, a decrease of approximately $74.6 million or 64.0 percent. The decrease was primarily due to lower natural gas prices associated with OGE Energy Resources, Inc. (OERI) short-term physical natural gas purchase transactions and associated financial contracts. A reduction in the volume of OERI s short-term physical natural gas activity and associated financial contracts outstanding at December 31, 2006 from December 31, 2005 also contributed to the decrease.

The balance of Gas Imbalance asset was approximately $2.8 million and $32.0 million at December 31, 2006 and 2005, respectively, a decrease of approximately $29.2 million or 91.3 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 at December 31, 2005 with no comparable balance at December 31, 2006. The decrease in park and loan transactions was due to the expiration of 2005 park and loan transactions in OERI s business activities. Operational imbalances were approximately $2.8 million and $16.3 million at December 31, 2006 and 2005, respectively, a decrease of approximately $13.5 million or 82.8 percent. The decrease in operational imbalances was primarily due to Enogex beginning to manage imbalances related to its storage operations on a combined basis in 2006 for its two storage facilities which resulted in a decrease in net imbalance volumes.

The balance of Construction Work in Progress was approximately $191.1 million and $101.8 million at December 31, 2006 and 2005, respectively, an increase of approximately $89.3 million or 87.7 percent, primarily due to construction expenditures related to OG&E s Centennial wind farm in addition to construction expenditures related to the expansion of Enogex s gathering pipeline capacity on the west side of its system in western Oklahoma and the Texas Panhandle.

The balance of Regulatory Asset SFAS 158 was approximately $231.1 million at December 31, 2006 with no comparable balance at December 31, 2005. The balance of Intangible Asset Unamortized Prior Service Cost was approximately $32.8 million at December 31, 2005 with no comparable balance at December 31, 2006. The balance of Prepaid Benefit Obligation was approximately $90.2 million at December 31, 2005 with no comparable balance at December 31, 2006. The change in these balances is due to the accounting change required upon adoption of SFAS No. 158, effective December 31, 2006, which required the Company to record the funded status of its pension and postretirement benefit plans on the Consolidated Balance Sheet (see Notes 1 and 2 of Notes to Consolidated Financial Statements for a further discussion).

The balance of Deferred Charges Other was approximately $23.1 million and $7.2 million at December 31, 2006 and 2005, respectively, an increase of approximately $15.9 million, primarily due to the creation of a regulatory asset at OG&E of approximately $14.7 million for the excess pension expense over the amount granted in rates by the OCC in OG&E s last Oklahoma rate case (see Note 1 of Notes to Consolidated Financial Statements for further discussion).

The balance of Short-Term Debt was approximately $30.0 million at December 31, 2005 with no comparable balance at December 31, 2006. The decrease was primarily due to proceeds received in October 2006 from the sale of Gathering s Kinta Assets in May 2006 which were used to pay down the commercial paper balance.

The balance of Accounts Payable was approximately $295.0 million and $510.4 million at December 31, 2006 and 2005, respectively, a decrease of approximately $215.4 million or 42.2 percent, primarily due to lower natural gas prices and volumes in December 2006 as compared to December 2005 and the timing of outstanding checks clearing the bank.

The balance of current Price Risk Management liabilities was approximately $9.2 million and $109.5 million at December 31, 2006 and 2005, respectively, a decrease of approximately $100.3 million or 91.6 percent. The decrease was primarily due to lower natural gas prices associated with OERI s short-term physical natural gas purchase transactions and associated financial contracts. A reduction in the volume of OERI s short-term physical natural gas activity and associated financial contracts outstanding at December 31, 2006 from December 31, 2005 also contributed to the decrease.

The balance of Gas Imbalance liability was approximately $11.1 million and $36.0 million at December 31, 2006 and 2005, respectively, a decrease of approximately $24.9 million or 69.2 percent. 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. Park and loan transactions were approximately $10.2 million at December 31, 2005 with no comparable balance at December 31, 2006. The decrease in park and loan transactions was due to the expiration of 2005 park and loan transactions in OERI s business activities. Operational imbalances were approximately $11.1 million and $25.8 million at December 31, 2006 and 2005, respectively, a decrease of approximately $14.7 million or 57.0 percent. The decrease in operational imbalances was primarily due to Enogex beginning to manage imbalances related to its storage operations on a combined basis in 2006 for its two storage facilities which resulted in a decrease in net imbalance volumes.

The balance of Fuel Clause Over Recoveries was approximately $96.3 million at December 31, 2006. The balance of Fuel Clause Under Recoveries was approximately $101.1 million at December 31, 2005. The increase in fuel clause over recoveries was due to the amount billed to OG&E s customers during 2006 exceeding OG&E s cost of fuel due to lower than expected natural gas prices and amounts recovered under approved tariffs exceeding the amounts intended by the December 2005 OCC rate order. OG&E s fuel recovery clauses are designed to smooth the impact of fuel price volatility on customers bills. As a result, OG&E typically 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. As described in more detail in Note 18 of Notes to Consolidated Financial Statements, the OCC, in its order dated December 12, 2005, granted OG&E a $42.3 million annual increase in the rates charged by OG&E to its retail customers in Oklahoma. These increased rates became effective in January 2006 pursuant to approved tariffs filed with the OCC. In January 2007, OG&E determined that the approved tariffs had inadvertently authorized OG&E to collect, and OG&E had collected, approximately $26.7 million of additional fuel-related revenues during 2006 that was not intended by the December 12, 2005 order. As a result, OG&E filed with the OCC in January 2007 amendments to its previously-authorized tariffs, in order to cease recovery of the fuel-related revenues not intended by the December 12, 2005 order. The $26.7 million, plus $1.2 million of interest, was recorded as a liability under Fuel Clause Over Recoveries on the Consolidated Balance Sheet in the fourth quarter of 2006, and such amounts, along with other Fuel Clause Over Recoveries, will be credited to OG&E s Oklahoma customers in 2007 and 2008 through OG&E s automatic fuel adjustment clause. In addition, OG&E recorded a reduction in operating revenues of approximately $26.7 million and an increase in interest expense of approximately $0.5 million, which resulted in an after tax reduction in net income of approximately $16.7 million in the fourth quarter of 2006. Because the rate increase authorized in the December 2005 order was not implemented until January 2006 and the tariffs were corrected effective December 31, 2006, the $26.7 million had no impact on net income for the year ended December 31, 2006. See additional discussion in Supplementary Data Interim Consolidated Financial Information (Unaudited).

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 Financial Accounting Standards Board (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,

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hedging or research and development services with, the Company. The Company has the following material off-balance sheet arrangements.

OG&E Railcar Lease Agreement

OG&E leases more than 1,400 railcars used to deliver coal to OG&E s coal-fired generation units. See Note 17 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 acquiring or constructing new facilities and replacing or expanding existing facilities at OG&E and at Enogex. Other working capital requirements are primarily related to maturing debt, operating lease obligations, hedging activities, natural gas storage, delays in recovering unconditional fuel purchase obligations and fuel clause under and over recoveries. 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)	$ 3,297.3	$ 426.5	$ 1,434.7	$ 1,070.1	$ 366.0
Enogex capital expenditures including capitalized interest	504.6	124.8	199.8	120.0	60.0
Other Operations capital expenditures	66.8	16.8	20.0	20.0	10.0
Total capital expenditures	3,868.7	568.1	1,654.5	1,210.1	436.0
Maturities of long-term debt	1,249.4	3.0	1.0	400.0	845.4
Interest payments on long-term debt	1,068.5	80.6	160.7	98.8	728.4
Pension funding obligations	129.7	50.0	46.1	33.6	N/A
Total capital requirements	6,316.3	701.7	1,862.3	1,742.5	2,009.8
Operating lease obligations					
OG&E railcars	52.0	4.0	7.7	40.3	---
Enogex noncancellable operating leases	8.6	2.2	3.1	2.9	0.4
Total operating lease obligations	60.6	6.2	10.8	43.2	0.4
Other purchase obligations and commitments					
OG&E cogeneration capacity payments	471.3	97.6	190.5	183.2	N/A
OG&E fuel minimum purchase commitments	614.5	198.0	220.0	173.1	23.4
Other	56.3	6.9	13.8	13.8	21.8
Total other purchase obligations and commitments	1,142.1	302.5	424.3	370.1	45.2
Total capital requirements, operating lease obligations and other purchase obligations and commitments	7,519.0	1,010.4	2,297.4	2,155.8	2,055.4
Amounts recoverable through automatic fuel adjustment clause (B)	(1,137.8)	(299.6)	(418.2)	(396.6)	(23.4)
Total, net	$ 6,381.2	$ 710.8	$ 1,879.2	$ 1,759.2	$ 2,032.0

(A) Under current environmental laws and regulations, OG&E may be required to spend approximately $600 million in capital expenditures on its coal-fired plants. These expenditures are expected to begin in 2007 and would continue over the next five years.

(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 18 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.

2006 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 $662.1 million and contractual obligations, net of recoveries through automatic fuel adjustment clauses, were approximately $10.7 million resulting in total net capital requirements and contractual obligations of approximately $672.9 million in 2006. Approximately $17.8 million of the 2006 capital requirements were to comply with environmental regulations. This compares to net capital requirements of approximately $448.8 million and net contractual obligations of approximately $4.3 million totaling approximately $453.1 million in 2005, of which approximately $19.2 million was to comply with environmental regulations. During 2006, 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 and 2006. During 2005 and 2006, these dispositions have generated net sales proceeds of approximately $277.6 million. Sales proceeds generated to date have been used to reduce short-term debt levels and fund capital expenditures.

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 2009 or 2011.

Future Capital Requirements

Capital Expenditures

The Company s current 2007 to 2012 construction program includes continued investment in OG&E s distribution, generation and transmission system and Enogex s pipeline assets. The Company s current estimates of capital expenditures for 2007 through 2012 are approximately $568.1 million, $838.6 million, $815.9 million, $659.9 million, $550.2 million and $436.0 million, respectively, which include capital expenditures of approximately $94.0 million, $278.8 million, $285.7 million, $97.7 million and $34.1 million, respectively, in 2007 through 2011 related to the construction of the Red Rock power plant. OG&E also has approximately 550 MW s of contracts with qualified cogeneration facilities (QF) and small power production producers (QF contracts) to meet its current and future expected customer needs. OG&E will continue reviewing all of the supply alternatives to these QF contracts that minimize the total cost of generation to its customers, including exercising its options (if applicable) to extend these QF contracts at pre-determined rates.

Pension and Postretirement Benefit Plans

During 2006, actual asset returns for the Company s defined benefit pension plan were positively affected by growth in the equity markets. At December 31, 2006, approximately 64 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 2006, asset returns on the pension plan were approximately 14.5 percent as compared to approximately 6.2 percent in 2005. 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 increased from approximately $32.0 million in 2005 to approximately $90.0 million in 2006. This increase in pension plan contributions in 2006 was to maintain an adequate funded status. 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. In August 2006, legislation was passed that changed the funding requirement for single- and multi-employer defined benefit pension plans as discussed below. During 2007, the Company may contribute up to $50 million to its pension plan.

In accordance with Statement of Financial Accounting Standard (SFAS) No. 88, Employer s Accounting for Settlements and Curtailments of Defined Benefit Pension Plans and for Termination Benefits, a one-time settlement charge is required to be recorded by an organization when lump sum payments or other settlements that relieve the organization from the responsibility for the pension benefit obligation during a plan year exceed the service cost and interest cost components of the organization s net periodic pension cost. During 2006, the Company experienced an increase in both the number of employees electing to retire and the amount of lump sum payments to be paid to such employees upon retirement in 2006. As a result, the Company recorded a pension settlement charge for 2006 of approximately $17.1 million in the fourth quarter of 2006. The pension settlement charge did not require a cash outlay by the Company and did not increase the Company s total pension expense over time, as the charge was an acceleration of costs that otherwise would have been recognized as pension expense in future periods. OG&E s Oklahoma jurisdictional portion of this charge was recorded as a regulatory asset (see Note 1 of Notes to Consolidated Financial Statements for a further discussion).

As discussed in Note 15 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.

At December 31, 2006, the projected benefit obligation and fair value of assets of the Company s pension plan and restoration of retirement income plan was approximately $585.0 million and $519.4 million, respectively, for an underfunded status of approximately $65.6 million. Also, at December 31, 2006, the accumulated postretirement benefit obligation and fair value of assets of the Company s postretirement benefit plans was approximately $225.4 million and $74.0 million, respectively, for an underfunded status of approximately $151.4 million. The above amounts have been recorded in Accrued Pension and Benefit Obligations with the offset in Accumulated Other Comprehensive Loss (except OG&E s portion which is recorded as a regulatory asset as discussed in Note 1 of Notes to Consolidated Financial Statements) in the Company s Consolidated Balance Sheet. The entry did not impact the results of operations in 2006 and did not require a usage of cash and is therefore excluded from the Consolidated Statement of Cash Flows. The amounts in Accumulated Other Comprehensive Loss and as a regulatory asset represent a net periodic pension cost to be recognized in the Consolidated Statements of Income in future periods.

During 2005, the Company made contributions to the pension plan that exceeded amounts previously recognized as net periodic pension expense and recorded a net prepaid benefit obligation at December 31, 2005 of approximately $88.9 million. At December 31, 2005, the Company s projected pension benefit obligation exceeded the fair value of the pension plan assets by approximately $154.6 million. 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 at December 31, 2005. 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 and did not require a usage of cash and is therefore excluded from the Consolidated Statement 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.

Pension Plan Costs and Assumptions

On August 17, 2006, President Bush signed The Pension Protection Act of 2006 (the Pension Protection Act) into law. The Pension Protection Act makes changes to important aspects of qualified retirement plans. Among other things, it

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introduces a new funding requirement for single- and multi-employer defined benefit pension plans, provides legal certainty on a prospective basis for cash balance and other hybrid plans and addresses contributions to defined contribution plans, deduction limits for contributions to retirement plans and investment advice provided to plan participants. The Company is currently analyzing the impact of the Pension Protection Act on its pension plans.

Long-Term Debt with Optional Redemption Provisions

OG&E s $125.0 million principal amount 6.65 percent Senior Notes (Senior Notes) due July 15, 2027, are repayable on July 15, 2007, at the option of the holders, at 100 percent of the principal amount, together with accrued and unpaid interest to July 15, 2007. Only holders who submit requests for repayment between May 15, 2007 and June 15, 2007 are entitled to such repayments. In accordance with SFAS No. 6, Classification of Short-Term Obligations Expected to Be Refinanced, OG&E reclassified the Senior Notes from long-term debt due within one year to long-term debt at December 31, 2006 due to OG&E having sufficient long-term liquidity in place as a result of increasing its revolving credit agreement to $400.0 million in December 2006. Also, based on where the Senior Notes have recently traded, OG&E does not believe it is probable that this option will be exercised by the note holders.

SPP Letter of Credit

On October 31, 2006, OG&E submitted a commercial letter of credit to the Southwest Power Pool for approximately $2.9 million related to the costs of upgrades required for OG&E to obtain transmission service from its new Centennial wind farm. This commercial letter of credit is not recorded as a liability on the Company s Consolidated Balance Sheet.

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, the issuance of long and short-term debt and proceeds from the sales of common stock to the public through the Company s Automatic Dividend Reinvestment and Stock Purchase Plan or other offerings will be adequate over the next three years to meet anticipated cash needs. 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

Short-term borrowings generally are used to meet working capital requirements. In December 2006, the Company and OG&E increased their aggregate available borrowing capacity under their revolving credit agreements from $750.0 million to $1.0 billion, $600 million for the Company and $400 million for OG&E. Also, OG&E has the necessary regulatory approvals to incur up to $800 million in short-term borrowings at any time for a two-year period beginning January 1, 2007 and ending December 31, 2008. See Note 14 of Notes to Consolidated Financial Statements for a discussion of the Company s short-term debt activity.

Common Stock

See Note 11 of Notes to Consolidated Financial Statements for a discussion of the Company s common stock activity.

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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, asset retirement obligations, fair value and cash flow hedges, regulatory assets and liabilities, unbilled revenues for OG&E, operating revenues for Enogex, natural gas purchases for Enogex, the allowance for uncollectible accounts receivable and the valuation of energy purchase and sale contracts. 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 Postretirement Benefit Plans

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 15 of Notes to Consolidated Financial Statements. The assumed return on plan assets is based on management s expectation of the long-term return on the plan assets portfolio. The discount rate used to compute the present value of plan liabilities is based generally on rates of high-grade corporate bonds with maturities similar to the average period over which benefits will be paid. The level of funding is dependent on returns on plan assets and future discount rates. Higher returns on plan assets and an increase in discount rates will reduce funding requirements to the pension plan. The following table indicates the sensitivity of the pension plan funded status to these variables.

	Change	Impact on Funded Status
Actual plan asset returns	+/- 5 percent	+/- $26.0 million
Discount rate	+/-0.25 percent	+/- $19.5 million
Contributions	+ $10.0 million	+ $10.0 million
Expected long-term return on plan assets	+/- 1 percent	None

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 have not been included in the 2007 earnings guidance.

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 and income tax related items. 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.

Asset Retirement Obligations

In accordance with FASB Interpretation No. 47, Accounting for Conditional Asset Retirement Obligations, an entity was required to recognize a liability for the fair value of an asset retirement obligation (ARO) that was conditional on a future event if the liability s fair value could be reasonably estimated. The fair value of a liability for the conditional ARO was recognized when incurred. Uncertainty surrounding the timing and method of settlement of a conditional ARO was factored into the measurement of the liability when sufficient information existed. However, in some cases, there was insufficient information to estimate the fair value of an ARO. In these cases, the liability was initially recognized in the period in which sufficient information was available for an entity to make a reasonable estimate of the liability s fair value. In the fourth quarter of 2006, OG&E recorded an ARO for approximately $0.9 million related to its Centennial wind farm. Beginning January 1, 2007, the Company will amortize the remaining value of the related ARO asset over the estimated remaining life of 99 years. The Company has also identified other ARO s that have not been recorded because the Company determined that these assets have indefinite lives primarily related to Enogex s processing plants and compression sites.

Hedging Policies

Enogex engages in cash flow 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, hedging requirements and are executed based upon management established price targets. During 2004 and 2005, Enogex and OERI utilized hedge accounting under SFAS No. 133 to manage commodity exposure for contractual length and operational storage natural gas, keep-whole natural gas and certain types of natural gas liquid hedges. During 2006, Enogex and OERI utilized hedge accounting under SFAS No. 133 to manage commodity exposure for contractual length and operational storage natural gas, keep-whole natural gas, natural gas liquid hedges and certain transportation hedges. 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 engage in cash flow and fair value hedge transactions to modify the rate composition of the debt portfolio. During 2004, OG&E and Enogex entered into interest rate swap agreements and, during 2005 and 2006, OG&E entered into 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 qualified 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 in late 2005 was to protect against the variability of future payments of interest expense of debt that was issued by OG&E in January 2006 and the objective of the treasury lock agreement in November 2006 is to protect against the variability of future interest payments of long-term debt that is expected to be issued during the first half of 2007.

Electric Utility Segment

Regulatory Assets and Liabilities

OG&E, as a regulated utility, is subject to the accounting principles prescribed by 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 Company adopted certain provisions of SFAS No. 158, Employers Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statements No. 87, 88, 106 and 132R, effective December 31, 2006, which requires the Company to separately disclose the items that have not yet been recognized as components of net periodic pension cost including, net loss, prior service cost and net transition obligation at December 31, 2006. For companies not subject to SFAS No. 71, SFAS No. 158 required this information to be included in

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Accumulated Other Comprehensive Income. However, for companies subject to SFAS No. 71, this information is allowed to be recorded as a regulatory asset if: (i) the utility has historically recovered and currently recovers pension and postretirement benefit plan expense in its electric rates; and (ii) there is no negative evidence that the existing regulatory treatment will change. Therefore, OG&E has recorded the net loss, prior service cost and net transition obligation as a regulatory asset as these expenses are probable of future recovery. If, in the future, the regulatory bodies indicated a change in policy related to the recovery of pension and postretirement benefit plan expenses, this could cause the SFAS No. 158 regulatory asset balance to be reclassified to Accumulated Other Comprehensive Income.

Unbilled Revenues

OG&E reads its customers meters and sends bills to its customers throughout each month. As a result, there is a significant amount of customers electricity consumption that has not been billed at the end of each month. Unbilled revenue is presented in Accrued Unbilled Revenues on the Consolidated Balance Sheets and in Operating Revenues on the Consolidated Statements of Income based on estimates of usage and prices during the period. At December 31, 2006, 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 $0.2 million. At December 31, 2006 and 2005, Accrued Unbilled Revenues were approximately $39.7 million and $41.8 million, respectively. The estimates that management uses in this calculation could vary from the actual amounts to be paid by customers.

Allowance for Uncollectible Accounts Receivable

Customer balances are generally written off if not collected within six months after the final billing date. The allowance for uncollectible accounts receivable 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, 2006, if the provision rate were to increase or decrease by 10 percent, this would cause a change in the uncollectible expense recognized of approximately $0.3 million. The allowance for uncollectible accounts receivable is a reduction to Accounts Receivable, Net 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 $3.3 million and $2.5 million at December 31, 2006 and 2005, respectively.

Natural Gas Pipeline Segment

Operating Revenues

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

Natural Gas Purchases

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.

Energy Purchase and Sale Contracts

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

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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, 2006, unrealized mark-to-market gains were approximately $31.2 million, which included approximately $0.5 million of unrealized mark-to-market gains that were calculated utilizing models. At December 31, 2006, a price movement of one percent for prices verified by independent parties would result in changes in unrealized mark-to-market gains of less than $0.1 million and a price movement of five percent on model-based prices would result in changes in unrealized mark-to-market gains of approximately $0.1 million. Energy contracts are presented in Price Risk Management assets, liabilities or against the brokerage deposits in Other Current Assets on the Consolidated Balance Sheets and in Operating Revenues on the Consolidated Statements of Income.

Natural Gas Inventory

Natural gas inventory is held by Enogex Inc. and OERI. Enogex Inc. maintains of natural gas inventory to provide operational support for its pipeline deliveries. As part of its recurring business activity, OERI injects and withdraws natural gas in to and out of inventory under the terms of its storage capacity contracts. In order to mitigate market price exposures, OERI enters into contracts or hedging instruments to protect the cash flows associated with its 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 Price Risk Management assets, liabilities or against the brokerage deposits in Other Current Assets with an offsetting gain or loss recorded in current earnings. All natural gas inventory held by Enogex is recorded at the lower of cost or market. During 2006, Enogex recorded write-downs to market value related to natural gas storage inventory of approximately $18.7 million. The amount of Enogex s natural gas inventory was approximately $35.9 million and $35.7 million at December 31, 2006 and 2005, 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.

Allowance for Uncollectible Accounts Receivable

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, Net 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 $1.1 million and $1.2 million at December 31, 2006 and 2005, respectively.

Accounting Pronouncements

See Notes 2 and 3 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 also 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 are described in more detail in Note 18 of Notes to Consolidated Financial Statements. OG&E is also subject to competition in various degrees from state-owned electric systems, municipally-owned electric systems, rural electric cooperatives and, in certain respects, from other private utilities, power marketers and cogenerators. OG&E has a franchise to serve in more than 270 towns and cities throughout its service territory. In a citywide election in May 2006, Oklahoma City voters approved a 25-year franchise for OG&E which is the largest city in OG&E s service territory.

Commitments and Contingencies

Except as disclosed otherwise in this Form 10-K, management, after consultation with legal counsel, does not currently anticipate that liabilities arising out of these pending or threatened lawsuits, claims and contingencies will have a material adverse effect on the Company s consolidated financial position, results of operations or cash flows. See Notes 17 and 18 of Notes to Consolidated Financial Statements and Item 3 of Part I in this Form 10-K 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, changes in 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, treasury lock 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, treasury lock 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.

Cash Flow Hedge of Interest Rates

OG&E entered into a treasury lock agreement, effective November 17, 2006, to hedge interest payments on the first $50.0 million of long-term debt that is expected to be issued during the first half of 2007. This treasury lock expires March 29, 2007.

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, 2006, 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.

Year ended December 31 *(Dollars in millions)*	2007	2008	2009	2010	2011	Thereafter	Total	12/31/06 Fair Value
Fixed-rate debt (A)								
Principal amount	$ 3.0	$ 1.0	$ ---	$400.0	$ ---	$ 810.0	$ 1,214.0	$ 1,254.2
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	---	---	---	---	---	3.56%	3.56%	---

(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 change interest expense by approximately $1.4 million annually.

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The Company s price risk management assets and liabilities as of December 31, 2006 were as follows:

December 31 *(In millions)*	Commodity	Notional Volume (MMBtu)	Maturity	Fair Value
TRADING				
Price Risk Management Assets				
Physical Purchases	Natural Gas	12.4	2007	$ 1.4
Physical Purchases	Natural Gas	1.5	2008	0.3
Total Physical Purchases				1.7
Physical Sales	Natural Gas	24.7	2007	28.1
Short Physical Options	Natural Gas	39.9	2007	2.7
Short Financial Swaps (excluding basis)	Natural Gas	0.4	2007	1.1
Long Basis Positions	Natural Gas	15.0	2007	7.6
Long Basis Positions	Natural Gas	2.8	2008	1.1
Long Basis Positions	Natural Gas	0.9	2009	0.2
Total Long Basis Positions				8.9
Short Basis Positions	Natural Gas	1.2	2007	0.1
Total Trading Price Risk Management Assets				$ 42.6
TRADING				
Price Risk Management Liabilities				
Physical Purchases	Natural Gas	19.1	2007	$ 1.7
Physical Purchases	Natural Gas	0.5	2008	0.3
Total Physical Purchases				2.0
Physical Sales	Natural Gas	9.1	2007	1.6
Long Physical Options	Natural Gas	1.5	2007	1.0
Long Financial Swaps (excluding basis)	Natural Gas	0.3	2007	1.4
Short Basis Positions	Natural Gas	11.0	2007	3.3
Short Basis Positions	Natural Gas	3.3	2008	0.5
Short Basis Positions	Natural Gas	0.9	2009	0.3
Total Short Basis Positions				4.1
Total Trading Price Risk Management Liabilities				$ 10.1
NON-TRADING				
Price Risk Management Assets				
Treasury Lock	Interest Rates	N/A	2007	$ 0.9
Short Financial Swaps (excluding basis)	Natural Gas	0.1	2007	0.1
Total Non-Trading Price Risk Management Assets				$ 1.0
NON-TRADING				
Price Risk Management Liabilities				
Short Basis Positions	Natural Gas	0.2	2007	$ 0.2
Total Non-Trading Price Risk Management Liabilities				$ 0.2

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 set by the Risk Oversight Committee. Those trading stop loss limits currently are $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 set by the Risk Oversight Committee for the Company s trading activities, assuming a one day time horizon and 95 percent confidence level, currently 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 quoted market prices over the next 12 months. The result of this analysis, which may differ from actual results, is as follows for 2006.

(In millions)	Trading
Commodity market risk, net	$ 0.1

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 2006.

(In millions)	Non-Trading
Commodity market risk, net	$ 10.8

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 (i) commodity contracts for the purchase and sale of natural gas by its subsidiaries, Enogex Inc. and Enogex Gas Gathering, L.L.C.; (ii) commodity contracts for the sale of natural gas liquids produced by its subsidiary, Enogex Products Corporation; (iii) electric power contracts by OG&E; and (iv) 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 that is refunded when the account is closed. New residential customers, whose outside credit scores indicate risk, are required to provide a security deposit that is refunded after 12 months of good payment history based on the applicable utility regulation. The payment behavior of all existing customers is continuously monitored and, if the payment behavior indicates sufficient risk within the meaning of the applicable utility regulation, customers will be required to provide a security deposit.

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 that 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.

Financial Statements and Supplementary Data.

OGE ENERGY CORP.

CONSOLIDATED STATEMENTS OF INCOME

Year ended December 31 *(In millions, except per share data)*	**2006**	2005	2004
OPERATING REVENUES			
Electric Utility operating revenues	**$ 1,745.7**	$ 1,720.7	$ 1,578.1
Natural Gas Pipeline operating revenues	**2,259.9**	4,190.8	3,284.5
Total operating revenues	**4,005.6**	5,911.5	4,862.6
COST OF GOODS SOLD (exclusive of depreciation shown below)			
Electric Utility cost of goods sold	**902.5**	946.6	869.1
Natural Gas Pipeline cost of goods sold	**2,000.0**	3,995.7	3,068.6
Total cost of goods sold	**2,902.5**	4,942.3	3,937.7
Gross margin on revenues	**1,103.1**	969.2	924.9
Other operation and maintenance	**416.6**	394.9	384.2
Depreciation	**181.4**	182.6	172.1
Impairment of assets	**0.3**	---	7.8
Taxes other than income	**72.1**	69.3	66.3
OPERATING INCOME	**432.7**	322.4	294.5
OTHER INCOME (EXPENSE)			
Interest income	**6.2**	3.5	4.9
Allowance for equity funds used during construction	**4.1**	---	0.9
Other income (loss)	**16.3**	(0.3)	10.5
Other expense	**(16.7)**	(5.5)	(4.7)
Net other income (expense)	**9.9**	(2.3)	11.6
INTEREST EXPENSE			
Interest on long-term debt	**87.4**	80.0	69.4
Interest expense unconsolidated affiliate	**---**	---	13.7
Allowance for borrowed funds used during construction	**(4.5)**	(2.2)	(1.7)
Interest on short-term debt and other interest charges	**13.1**	12.5	9.4
Interest expense	**96.0**	90.3	90.8
INCOME FROM CONTINUING OPERATIONS BEFORE TAXES	**346.6**	229.8	215.3
INCOME TAX EXPENSE	**120.5**	68.6	73.4
INCOME FROM CONTINUING OPERATIONS	**226.1**	161.2	141.9
DISCONTINUED OPERATIONS (NOTE 8)			
Income from discontinued operations	**59.1**	84.2	18.6
Income tax expense	**23.1**	34.4	7.0
Income from discontinued operations	**36.0**	49.8	11.6
NET INCOME	**$ 262.1**	$ 211.0	$ 153.5
BASIC AVERAGE COMMON SHARES OUTSTANDING	**91.0**	90.3	88.0
DILUTED AVERAGE COMMON SHARES OUTSTANDING	**92.1**	90.8	88.5
BASIC EARNINGS PER AVERAGE COMMON SHARE			
Income from continuing operations	**$ 2.48**	$ 1.79	$ 1.61
Income from discontinued operations, net of tax	**0.40**	0.55	0.13
NET INCOME	**$ 2.88**	$ 2.34	$ 1.74
DILUTED EARNINGS PER AVERAGE COMMON SHARE			
Income from continuing operations	**$ 2.45**	$ 1.77	$ 1.60
Income from discontinued operations, net of tax	**0.39**	0.55	0.13
NET INCOME	**$ 2.84**	$ 2.32	$ 1.73
DIVIDENDS DECLARED PER SHARE	**$ 1.3375**	$ 1.33	$ 1.33

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

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OGE ENERGY CORP.

CONSOLIDATED BALANCE SHEETS

December 31 *(In millions)*	**2006**	2005
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	**$ 47.9**	$ 26.4
Funds on deposit	**32.0**	---
Accounts receivable, net	**344.3**	591.4
Accrued unbilled revenues	**39.7**	41.8
Fuel inventories	**65.6**	63.6
Materials and supplies, at average cost	**58.7**	56.5
Price risk management	**41.9**	116.5
Gas imbalances	**2.8**	32.0
Accumulated deferred tax assets	**10.6**	14.3
Fuel clause under recoveries	**---**	101.1
Prepayments	**9.0**	10.6
Other	**11.6**	19.4
Total current assets	**664.1**	1,073.6
OTHER PROPERTY AND INVESTMENTS, at cost	**35.2**	29.2
PROPERTY, PLANT AND EQUIPMENT		
In service	**6,307.7**	5,999.4
Construction work in progress	**191.1**	101.8
Total property, plant and equipment	**6,498.8**	6,101.2
Less accumulated depreciation	**2,631.3**	2,568.7
Net property, plant and equipment	**3,867.5**	3,532.5
In service of discontinued operations	**---**	60.6
Less accumulated depreciation	**---**	25.7
Net property, plant and equipment of discontinued operations	**---**	34.9
Net property, plant and equipment	**3,867.5**	3,567.4
DEFERRED CHARGES AND OTHER ASSETS		
Income taxes recoverable from customers, net	**31.1**	32.8
Regulatory asset - SFAS 158	**231.1**	---
Intangible asset - unamortized prior service cost	**---**	32.8
Prepaid benefit obligation	**---**	90.2
Price risk management	**1.7**	9.0
McClain Plant deferred expenses	**18.7**	24.9
Unamortized loss on reacquired debt	**20.1**	21.3
Unamortized debt issuance costs	**9.4**	8.1
Other	**23.1**	7.2
Deferred charges and other assets of discontinued operations	**---**	2.4
Total deferred charges and other assets	**335.2**	228.7
TOTAL ASSETS	**$ 4,902.0**	$ 4,898.9

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

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OGE ENERGY CORP.

CONSOLIDATED BALANCE SHEETS (Continued)

December 31 *(In millions)*	**2006**	2005
LIABILITIES AND STOCKHOLDERS EQUITY		
CURRENT LIABILITIES		
Short-term debt	**$ ---**	$ 30.0
Accounts payable	**295.0**	510.4
Dividends payable	**31.1**	30.1
Customers deposits	**53.4**	47.8
Accrued taxes	**57.0**	67.1
Accrued interest	**37.7**	31.9
Accrued compensation	**46.0**	40.3
Long-term debt due within one year	**3.0**	---
Price risk management	**9.2**	109.5
Gas imbalances	**11.1**	36.0
Fuel clause over recoveries	**96.3**	---
Other	**33.2**	47.5
Total current liabilities	**673.0**	950.6
LONG-TERM DEBT	**1,346.3**	1,350.8
COMMITMENTS AND CONTINGENCIES (NOTE 17)		
DEFERRED CREDITS AND OTHER LIABILITIES		
Accrued pension and benefit obligations	**231.3**	234.5
Accumulated deferred income taxes	**859.2**	807.1
Accumulated deferred investment tax credits	**26.8**	31.7
Accrued removal obligations, net	**125.5**	114.3
Price risk management	**1.1**	10.7
Other	**35.0**	23.4
Total deferred credits and other liabilities	**1,278.9**	1,221.7
STOCKHOLDERS EQUITY		
Common stockholders equity	**741.0**	715.5
Retained earnings	**890.8**	750.5
Accumulated other comprehensive loss, net of tax	**(28.0)**	(90.2)
Total stockholders equity	**1,603.8**	1,375.8
TOTAL LIABILITIES AND STOCKHOLDERS EQUITY	**$ 4,902.0**	$ 4,898.9

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

OGE ENERGY CORP.

CONSOLIDATED STATEMENTS OF CAPITALIZATION

December 31 *(In millions)*		**2006**	2005
STOCKHOLDERS EQUITY			
Common stock, par value $0.01 per share; authorized 125.0 shares; and outstanding 91.2 and 90.6 shares, respectively		**$ 0.9**	$ 0.9
Premium on capital stock		**740.1**	714.6
Retained earnings		**890.8**	750.5
Accumulated other comprehensive loss, net of tax		**(28.0)**	(90.2)
Total stockholders equity		**1,603.8**	1,375.8
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		**(0.7)**	(0.8)
Senior Notes - OG&E			
5.15 %	Senior Notes, Series Due January 15, 2016	**110.0**	---
6.50 %	Senior Notes, Series Due July 15, 2017	**125.0**	125.0
6.65 %	Senior Notes, Series Due July 15, 2027	**125.0**	125.0
6.50 %	Senior Notes, Series Due April 15, 2028	**100.0**	100.0
6.50 %	Senior Notes, Series Due August 1, 2034	**140.0**	140.0
5.75 %	Senior Notes, Series Due January 15, 2036	**110.0**	---
Other Bonds - OG&E			
3.11% - 4.05%	Garfield Industrial Authority, January 1, 2025	**47.0**	47.0
3.20% - 4.13%	Muskogee Industrial Authority, January 1, 2025	**32.4**	32.4
3.03% - 4.06%	Muskogee Industrial Authority, June 1, 2027	**56.0**	56.0
Other long-term debt (NOTE 14)		**---**	220.0
Unamortized discount		**(2.1)**	(1.4)
Enogex Notes			
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**	400.0
Unamortized swap monetization		**2.7**	3.6
Total long-term debt		**1,349.3**	1,350.8
Less long-term debt due within one year		**3.0**	---
Total long-term debt (excluding long-term debt due within one year)		**1,346.3**	1,350.8
Total Capitalization		**$ 2,950.1**	$ 2,726.6

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

OGE ENERGY CORP.

CONSOLIDATED STATEMENTS OF RETAINED EARNINGS

Year ended December 31 *(In millions)*	**2006**	2005	2004
BALANCE AT BEGINNING OF PERIOD	**$ 750.5**	$ 659.8	$ 623.9
ADD: Net income	**262.1**	211.0	153.5
Total	**1,012.6**	870.8	777.4
DEDUCT: Dividends declared on common stock	**121.8**	120.3	117.6
BALANCE AT END OF PERIOD	**$ 890.8**	$ 750.5	$ 659.8

OGE ENERGY CORP.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Year ended December 31 *(In millions)*	**2006**	2005	2004
Net income	**$ 262.1**	$ 211.0	$ 153.5
Other comprehensive income (loss), net of tax:			
Minimum pension liability adjustment [$148.6, ($30.0) and ($21.2) pre-tax, respectively]	**91.1**	(18.4)	(13.0)
Deferred hedging gains (losses) [$4.1, $4.7 and ($1.1) pre-tax, respectively]	**2.5**	2.9	(0.7)
Reversal of unrealized gains on available-for-sale securities [($0.6) pre-tax]	**---**	---	(0.4)
Settlement and amortization of cash flow hedge [$0.5, $0.5, and ($4.0) pre-tax, respectively]	**0.3**	0.3	(2.5)
Total other comprehensive income (loss), net of tax	**93.9**	(15.2)	(16.6)
Total comprehensive income	**$ 356.0**	$ 195.8	$ 136.9

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)*	**2006**	2005	2004
CASH FLOWS FROM OPERATING ACTIVITIES			
Income from continuing operations	**$ 226.1**	$ 161.2	$ 141.9
Adjustments to reconcile income from continuing operations to net cash provided from operating activities			
Depreciation	**181.4**	182.6	172.1
Impairment of assets	**0.3**	---	7.8
Deferred income taxes and investment tax credits, net	**32.3**	21.9	50.5
Allowance for equity funds used during construction	**(4.1)**	---	(0.9)
(Gain) loss on sale of assets	**(1.6)**	0.1	(6.5)
Loss on retirement of fixed assets	**6.0**	---	---
Stock-based compensation expense	**3.8**	0.9	3.5
Excess tax benefit on stock-based compensation	**(1.4)**	---	---
Price risk management assets	**81.9**	(62.6)	(20.0)
Price risk management liabilities	**(101.7)**	80.1	9.5
Other assets	**(73.4)**	(6.4)	(28.2)
Other liabilities	**12.3**	(2.9)	7.5
Change in certain current assets and liabilities			
Funds on deposit	**(32.0)**	---	---
Accounts receivable, net	**247.1**	(106.9)	(136.5)
Accrued unbilled revenues	**2.1**	3.7	(7.5)
Fuel, materials and supplies inventories	**(4.4)**	22.1	52.5
Gas imbalance asset	**29.2**	67.8	(29.8)
Fuel clause under recoveries	**101.1**	(46.8)	(50.3)
Other current assets	**9.3**	12.4	10.0
Accounts payable	**(215.4)**	40.1	194.2
Customers deposits	**5.6**	(0.5)	6.7
Accrued taxes	**(7.2)**	53.9	(4.5)
Accrued interest	**5.8**	(0.9)	(0.7)
Accrued compensation	**5.7**	2.9	0.7
Gas imbalance liability	**(24.9)**	19.7	(6.5)
Fuel clause over recoveries	**96.3**	---	(32.4)
Other current liabilities	**(10.7)**	(4.5)	11.1
Net Cash Provided from Operating Activities	**569.5**	437.9	344.2
CASH FLOWS FROM INVESTING ACTIVITIES			
Capital expenditures (less allowance for equity funds used during construction)	**(486.6)**	(297.2)	(428.6)
Proceeds from sale of assets	**3.2**	5.8	9.2
Other investing activities	**(0.1)**	0.1	0.7
Net Cash Used in Investing Activities	**(483.5)**	(291.3)	(418.7)
CASH FLOWS FROM FINANCING ACTIVITIES			
Proceeds from long-term debt	**217.5**	---	186.0
Retirement of long-term debt	**---**	(254.3)	(206.2)
(Decrease) increase in short-term debt, net	**(250.0)**	125.0	(77.5)
Issuance of common stock	**14.5**	14.7	62.5
Excess tax benefit on stock-based compensation	**1.4**	---	---
Dividends paid on common stock	**(120.8)**	(120.0)	(114.6)
Net Cash Used in Financing Activities	**(137.4)**	(234.6)	(149.8)
DISCONTINUED OPERATIONS			
Net cash (used in) provided from operating activities	**(19.9)**	(43.0)	47.4
Net cash provided from (used in) investing activities	**92.8**	146.4	(3.1)
Net cash used in financing activities	**---**	(0.1)	(21.4)
Net Cash Provided from Discontinued Operations	**72.9**	103.3	22.9

NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	**21.5**	15.3	(201.4)
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	**26.4**	11.1	212.5
CASH AND CASH EQUIVALENTS AT END OF PERIOD	**$ 47.9**	$ 26.4	$ 11.1

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

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. OG&E is the largest electric utility in Oklahoma and its franchised service territory includes the Fort Smith, Arkansas area. OG&E sold its retail 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 May 2006, Enogex Gas Gathering, L.L.C. (Gathering), a wholly-owned subsidiary of Enogex Inc., sold certain gas gathering assets in the Kinta, Oklahoma, area, which have been reported as discontinued operations in the Company s Consolidated Financial Statements (see Note 8 for a further discussion). In December 2006, Enogex entered into a joint venture arrangement with a third party. The joint venture, Atoka Midstream, LLC, intends to construct, own and operate a gathering system and processing plant and related facilities relating to production in certain areas in southeastern Oklahoma. Enogex holds its 50 percent membership interest in Atoka Midstream LLC through Enogex Atoka LLC (Enogex Atoka), a wholly-owned subsidiary of Enogex Inc. Enogex Atoka will act as the managing member and operator of the facilities owned by the joint venture.

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:

December 31 *(In millions)*	**2006**	2005
Regulatory Assets		
Regulatory asset - SFAS 158	**$ 231.1**	$ ---
Income taxes recoverable from customers, net	**31.1**	32.8
Unamortized loss on reacquired debt	**20.1**	21.3
McClain Plant deferred expenses	**18.7**	24.9
Pension plan expenses	**14.7**	---
Cogeneration credit rider under recovery	**3.1**	3.7
Fuel clause under recoveries	**---**	101.1
Recoverable take or pay gas charges	**---**	4.9
Miscellaneous	**0.4**	0.5
Total Regulatory Assets	**$ 319.2**	$ 189.2
Regulatory Liabilities		
Accrued removal obligations, net	**$ 125.5**	$ 114.3
Fuel clause over recoveries	**96.3**	---
Deferred gain on sale of assets	**2.7**	3.8
Total Regulatory Liabilities	**$ 224.5**	$ 118.1

The Company adopted SFAS No. 158, Employers Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statements No. 87, 88, 106 and 132R, effective December 31, 2006, which requires the Company to separately disclose the items that have not yet been recognized as components of net periodic pension cost including, net loss, prior service cost and net transition obligation at December 31, 2006. For companies not subject to SFAS No. 71, SFAS No. 158 required this information to be included in Accumulated Other Comprehensive Income. However, for companies subject to SFAS No. 71, this information is allowed to be recorded as a regulatory asset if: (i) the utility has historically recovered and currently recovers pension and postretirement benefit plan expense in its electric rates; and (ii) there is no negative evidence that the existing regulatory treatment will change. Therefore, OG&E has recorded the net loss, prior service cost and net transition obligation as a regulatory asset as these expenses are probable of future recovery. If, in the future, the regulatory bodies indicated a change in policy related to the recovery of pension and postretirement benefit plan expenses, this could cause the SFAS No. 158 regulatory asset balance to be reclassified to Accumulated Other Comprehensive Income.

The components of the SFAS No. 158 regulatory asset at December 31, 2006 are as follows:

December 31 *(In millions)*	**2006**
Defined benefit pension plan:	
Net loss	**$ 129.9**
Prior service cost	**21.9**
Defined benefit postretirement plans:	
Net loss	**60.3**
Net transition obligation	**15.2**
Prior service cost	**3.8**
Total	**$ 231.1**

The following amounts in the SFAS No. 158 regulatory asset at December 31, 2006 are expected to be recognized as components of net periodic benefit cost in 2007:

Defined benefit pension plan:	
Net loss	**$ 8.1**
Prior service cost	**4.7**

Defined benefit postretirement plans:		
Net loss	**5.4**	
Net transition obligation	**2.5**	
Prior service cost	**1.5**	
Total	**$**	**22.2**

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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. The OCC authorized approximately $30.1 million of the $32.8 million regulatory asset balance at December 31, 2005 to be included in OG&E s rate base for purposes of earning a return.

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.

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 2002 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. At December 31, 2005, the McClain Plant regulatory asset was approximately $24.9 million which is being recovered over a four-year time period as authorized in the OCC rate order which began in January 2006. The OCC authorized approximately $15.5 million of the $24.9 million regulatory asset balance at December 31, 2005 to be included in OG&E s rate base for purposes of earning a return.

In accordance with the OCC order received by OG&E in December 2005 in its Oklahoma rate case, OG&E was allowed to recover a certain amount of pension plan expenses. At December 31, 2006, there was approximately $14.7 million of expenses exceeding this level primarily related to a pension settlement charge recorded by the Company during the fourth quarter of 2006 (see Note 15 for a further discussion). These excess amounts have been recorded as a regulatory asset as OG&E believes these expenses are probable of future recovery.

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 $3.1 million and $3.7 million, respectively, at December 31, 2006 and 2005. OG&E s cogeneration credit rider has been updated and approved by the OCC in December of each year through December 2006 and any over/under recovery of the cogeneration credit rider in the current year and prior periods has been automatically included in the next year s rider. OG&E s current cogeneration credit rider expired December 31, 2006. The 2007 cogeneration credit rider is approximately $80.7 million and the total under recovery through 2006 was approximately $3.1 million. OG&E expects to file an application with the OCC in late 2007 to request a cogeneration credit for years after 2007. The cogeneration credit rider under recovery was not included in OG&E s rate base and did not otherwise earn a rate of return. The cogeneration credit rider under recovery is included in Other Current Assets on the Company s Consolidated Balance Sheets.

Fuel clause under recoveries are generated from under recoveries from OG&E s customers when OG&E s cost of fuel exceeds the amount billed to its customers. Fuel clause over recoveries are generated from over recoveries from OG&E s customers when the amount billed to its customers exceeds OG&E s cost of fuel. OG&E s fuel recovery clauses are designed to smooth the impact of fuel price volatility on customers bills. As a result, OG&E typically 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 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. As described in more detail in Note 18, the OCC, in its order dated December 12, 2005, granted OG&E a $42.3 million annual increase in the rates charged by OG&E to its retail customers in Oklahoma. These increased rates became effective in January 2006 pursuant to approved tariffs filed with the OCC. In January 2007, OG&E determined that the approved tariffs had inadvertently authorized OG&E to collect, and OG&E had collected, approximately $26.7 million of additional fuel-related revenues during 2006 that was not intended by the December 12, 2005 order. As a result, OG&E filed with the OCC in January 2007 amendments to its previously-authorized tariffs, in order to cease recovery of the fuel-related revenues not intended by the December 12, 2005 order. The $26.7 million, plus $1.2 million of interest, was recorded as a liability under Fuel Clause Over Recoveries on the Consolidated Balance Sheet in the fourth quarter of 2006, and such amounts, along with other Fuel Clause Over Recoveries, will be credited to OG&E s Oklahoma customers in 2007 and 2008 through OG&E s automatic fuel adjustment clause. In addition, OG&E recorded a reduction in operating revenues of approximately $26.7 million and an increase in interest expense of approximately $0.5 million, which resulted in an after tax reduction in net income of approximately $16.7 million in the fourth quarter of 2006. Because the rate increase authorized in the December 2005 order was not implemented until January 2006 and the tariffs were corrected effective December 31, 2006, the $26.7 million had no impact on net income for the year ended December 31, 2006. See additional discussion in Supplementary Data Interim Consolidated Financial Information (Unaudited).

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 Oklahoma 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 and 2006 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, asset retirement obligations, fair value and cash flow hedges, regulatory assets and liabilities, unbilled revenues for OG&E, operating revenues for Enogex, natural gas purchases for Enogex, the allowance for uncollectible accounts receivable and the valuation of energy purchase and sale contracts.

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 $45.0 million and $55.0 million at December 31, 2006 and 2005, 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 $4.4 million and $3.7 million at December 31, 2006 and 2005, respectively.

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

For Enogex, credit risk is the risk of financial loss to Enogex if counterparties fail to perform their contractual obligations. Enogex maintains credit policies with regard to its counterparties that management believes minimize overall credit risk. These policies include the evaluation of a potential counterparty s financial 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 $13.7 million and $19.1 million for 2006 and 2005, respectively, based on the average cost of fuel purchased. The amount of fuel inventory was approximately $29.7 million and $27.9 million at December 31, 2006 and 2005, respectively.

Enogex

Natural gas inventory is held by Enogex Inc. and OGE Energy Resources, Inc. (OERI). Enogex Inc. maintains of natural gas inventory to provide operational support for its pipeline deliveries. As part of its recurring business activity, OERI injects and withdraws natural gas in to and out of inventory under the terms of its storage capacity contracts. In order to mitigate market price exposures, OERI enters into contracts or hedging instruments to protect the cash flows associated with its inventory. 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. 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. All natural gas inventory held by Enogex is recorded at the lower of cost or market. During 2006, Enogex recorded write-downs to market value related to natural gas storage inventory of approximately $18.7 million. The amount of Enogex s natural gas inventory was approximately $35.9 million and $35.7 million at December 31, 2006 and 2005, 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.

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 at December 31, 2005 and park and loan liabilities were approximately $10.2 million at December 31, 2005. There were no park and loan assets or liabilities at December 31, 2006. Operational imbalance assets were approximately $2.8 million and $16.3 million, respectively, at December 31, 2006 and 2005 and operational imbalance liabilities were approximately $11.1 million and $25.8 million, respectively, at December 31, 2006 and 2005.

Property, Plant and Equipment

OG&E

All property, plant and equipment are recorded at cost. Newly constructed plant is added to plant balances at cost which includes contracted services, direct labor, materials, overhead, transportation costs and the allowance for funds used during construction (AFUDC). Replacements of units of property are capitalized as plant. For assets that belong to a common plant account, the replaced plant is removed from plant balances and the cost of such property less net salvage is charged to Accumulated Depreciation. For assets that do not belong to a common plant account, the replaced plant is removed from plant balances with the related accumulated depreciation and the remaining balance 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 the 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 $176.2 million and $174.0 million, respectively, at December 31, 2006 and 2005. The accumulated depreciation associated with OG&E s interest in the McClain Plant is approximately $24.9 million and $14.3 million, respectively, at December 31, 2006 and 2005.

Enogex

All property, plant and equipment are recorded at cost. Newly constructed plant is added to plant balances at cost which includes contracted services, direct labor, materials, overhead, transportation costs and capitalized interest. Replacements of units of property are capitalized as plant. For assets that belong to a common plant account, the replaced plant is removed from plant balances and charged to Accumulated Depreciation. For assets that do not belong to a common plant account, the replaced plant is removed from plant balances with the related accumulated depreciation and the remaining balance 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, 2006 and 2005, respectively.

December 31 *(In millions)*	**2006**	2005
OGE Energy Corp. (holding company)		
Property, plant and equipment	**$ 80.7**	$ 76.3
OGE Energy Corp. property, plant and equipment	**80.7**	76.3
OG&E		
Distribution assets	**2,205.3**	2,080.6
Electric generation assets	**2,057.4**	1,907.1
Transmission assets	**663.2**	610.2
Intangible plant	**32.0**	8.6
Other property and equipment	**196.5**	221.4
OG&E property, plant and equipment	**5,154.4**	4,827.9
Enogex		

Transportation and storage assets	**691.5**	683.6
Gathering and processing assets	**564.6**	505.9
Marketing assets	**7.6**	7.5
Enogex property, plant and equipment	**1,263.7**	1,197.0
Total property, plant and equipment	**$ 6,498.8**	$ 6,101.2

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Depreciation

OG&E

The provision for depreciation, which was approximately 2.7 percent and 3.0 percent, respectively, of the average depreciable utility plant for 2006 and 2005, is provided on a straight-line method over the estimated service life of the utility assets. Depreciation is provided at the unit level for production plant and at the account or sub-account level for all other plant, and is based on the average life group method. In 2007, the provision for depreciation is projected to be approximately 2.7 percent of the average depreciable utility plant. Amortization of intangibles other than debt costs is computed using the straight-line method. Approximately 81 percent of the amortizable intangible plant balance at December 31, 2006 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

For OG&E, 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 7.79 percent, 3.78 percent and 4.99 percent for the years 2006, 2005 and 2004, respectively. The increase in the AFUDC rates in 2006 was primarily due to increased equity funds in the AFUDC calculation that resulted from a higher level of construction costs partially offset by a lower level of short-term borrowings in 2006.

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, contracted prices (considering current commodity prices), historical seasonal fluctuations and any known adjustments. The estimates are reversed in the following month and customers are billed on actual volumes and contracted prices. Gas sales are calculated on current month nominations and contracted prices. Operating revenues associated with the production of 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, Net 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 Other Current Assets 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

The Company adopted SFAS No. 123 (Revised), Share-Based Payment, using the modified prospective transition method, effective January 1, 2006, which required 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. See Note 3 for a further discussion related to the Company s stock-based compensation. The following table reflects pro forma net income and income per average common share for 2005 and 2004 had the Company elected to adopt the fair value recognition provisions of SFAS No. 123, Accounting for Stock-Based Compensation, for options granted under the Company s stock-based employee compensation plans. For purposes of this pro forma disclosure, the value of the options was determined using a Black-Scholes option pricing formula and amortized to expense over the options vesting periods. Pro forma information is not included for 2006 as all share-based payments have been accounted for under SFAS No. 123(R).

Year ended December 31 *(In millions, except per share data)*	2005	2004
Net income, as reported	$ 211.0	$ 153.5
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

Pro forma net income	$ 210.5	$ 152.5
Income per average common share		
Basic as reported	$ 2.34	$ 1.74
Diluted as reported	$ 2.32	$ 1.73
Basic pro forma	$ 2.33	$ 1.73
Diluted pro forma	$ 2.32	$ 1.72

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, 2006 and 2005 are as follows:

December 31 *(In millions)*	**2006**	2005
Defined benefit pension plan:		
Net loss, net of tax	**$ (21.4)**	$ ---
Prior service cost, net of tax	**(3.4)**	---
Defined benefit postretirement plans:		
Net loss, net of tax	**(5.4)**	---
Net transition obligation, net of tax	**(0.8)**	---
Prior service cost, net of tax	**(0.7)**	---
Deferred hedging gains, net of tax	**5.6**	3.1
Settlement and amortization of cash flow hedge, net of tax	**(1.9)**	(2.2)
Minimum pension liability adjustment, net of tax	**---**	(91.1)
Total accumulated other comprehensive loss, net of tax	**$ (28.0)**	$ (90.2)

Defined Benefit Pension and Postretirement Plans

The Company adopted certain provisions of SFAS No. 158 effective December 31, 2006, which requires the Company to separately disclose the items that have not yet been recognized as components of net periodic pension cost including, net loss, prior service cost and net transition obligation at December 31, 2006. The below amounts exclude amounts related to OG&E, since under SFAS No. 71, OG&E is allowed to record these expenses as a regulatory asset (see Note 1 for a future discussion). Accumulated other comprehensive loss included an after tax loss of approximately $21.4 million ($34.9 million pre-tax) and $3.4 million ($5.6 million pre-tax) at December 31, 2006 related to the net loss and prior service cost of its defined benefit pension plan, respectively. Accumulated other comprehensive loss included an after tax loss of approximately $5.4 million ($11.7 million pre-tax), $0.8 million ($1.2 million pre-tax) and $0.7 million ($1.2 million pre-tax) at December 31, 2006 related to the net loss, net transition obligation and prior service cost of its defined benefit postretirement plans, respectively.

The following amounts in accumulated other comprehensive loss at December 31, 2006 are expected to be recognized as components of net periodic benefit cost in 2007:

Defined benefit pension plan:	
Net loss, net of tax	**$ 1.3**
Prior service cost, net of tax	**0.7**
Defined benefit postretirement plans:	
Net loss, net of tax	**0.6**
Prior service cost, net of tax	**0.3**
Net transition obligation, net of tax	**0.1**
Total	**$ 3.0**

Minimum Pension Liability Adjustment

Accumulated other comprehensive loss included an after tax loss of approximately $91.1 million ($148.6 million pre-tax) at December 31, 2005 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.

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

Reclassifications

Certain prior year amounts have been reclassified on the Consolidated Financial Statements to conform to the 2006 presentation primarily related to discontinued operations.

2. Accounting Pronouncements

In July 2006, the FASB issued FASB Interpretation No. 48, Accounting for Uncertainty in Income Taxes, an interpretation of FASB Statement No. 109, which clarifies the accounting for uncertainty in income taxes recognized in an enterprise s financial statements in accordance with SFAS No. 109, Accounting for Income Taxes. This interpretation prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. This interpretation also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure and transition. This interpretation is effective for fiscal years beginning after December 15, 2006. The Company adopted this new interpretation effective January 1, 2007. As prescribed in the interpretation, the cumulative effect of applying the provisions of FIN No. 48 shall be reflected as an adjustment to the opening balance of Stockholders Equity. The Company estimates that this cumulative effect will be between approximately $3 million and $5 million. The Company also anticipates additional interest expense will be incurred during 2007 related to the method of accounting used to capitalize costs for self-constructed assets (see Note 10 for a further discussion).

In September 2006, the FASB issued SFAS No. 157, Fair Value Measurements, which defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles and expands disclosures about fair value measurements. SFAS No. 157 expands disclosures about the use of fair value to measure assets and liabilities in interim and annual periods subsequent to initial recognition. The guidance in SFAS No. 157 applies to derivatives and other financial instruments measured at fair value under SFAS No. 133 at initial recognition and in all subsequent periods. Therefore, SFAS No. 157 nullifies the guidance in footnote 3 of Emerging Issues Task Force 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. SFAS No. 157 also amends SFAS No. 133 to remove the guidance similar to that nullified in EITF 02-3. SFAS No. 157 is effective for financial statements issued for fiscal years beginning after November 15, 2007, and interim periods within those fiscal years. The provisions of SFAS No. 157 should be applied prospectively as of the beginning of the fiscal year in which it is initially applied, except in certain conditions. The Company will adopt this new standard effective January 1, 2008. Management has not yet determined what the impact of this new standard will be on its consolidated financial position or results of operations.

In September 2006, the FASB issued SFAS No. 158 which requires an employer to: (i) recognize the overfunded or underfunded status of a defined benefit postretirement plan (other than a multiemployer plan) as an asset or liability in its statement of financial position and to recognize changes in that funded status in the year in which the changes occur through comprehensive income of a business entity; and (ii) to measure the fair value of the funded status of a plan as of the date of its year-end statement of financial position, with limited exceptions. The requirement to initially recognize the funded status of the defined benefit postretirement plan and the disclosure requirements are effective for the year ended December 31, 2006 for the Company. The requirement to measure plan assets and benefit obligations at fair value in accordance with SFAS No. 157 as of the date of the employer s fiscal year-end statement of financial position is effective for fiscal years ending after December 15, 2008. The Company adopted provision (i) above of this new standard effective December 31, 2006. At December 31, 2006, the projected benefit obligation and fair value of assets of the Company s pension plan and restoration of retirement income plan was approximately $585.0 million and $519.4 million, respectively, for an underfunded status of approximately $65.6 million. Also, at December 31, 2006, the accumulated postretirement benefit obligation and fair value of assets of the Company s postretirement benefit plans was approximately $225.4 million and $74.0 million, respectively, for an underfunded status of approximately $151.4 million. The above amounts have been recorded in Accrued Pension and Benefit Obligations with the offset in Accumulated Other Comprehensive Loss (except OG&E s portion which is recorded as a regulatory asset as discussed in Note 1) in the Company s Consolidated Balance Sheet. The Company will adopt provision (ii) above of this new standard effective December 31, 2008. Management has not yet determined what the impact of provision (ii) of this new standard will be on its consolidated financial position or results of operations.

3. Stock-Based Compensation

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.

Prior to January 1, 2006, the Company accounted for the Plans under the recognition and measurement provisions of Accounting Principles Board (APB) Opinion No. 25, Accounting for Stock Issued to Employees, as permitted by SFAS No. 123. The Company also previously adopted the disclosure provisions under SFAS No. 123 and SFAS No. 148, Accounting for Stock-Based Compensation Transition and Disclosure. The Company recorded compensation expense of approximately $0.9 million pre-tax ($0.5 million after tax) and $3.5 million pre-tax ($2.1 million after tax) in 2005 and 2004, respectively, related to its performance units in Other Operation and Maintenance Expense in the Consolidated Statements of Income. No compensation expense related to stock options was recognized in 2005 or 2004 as all options granted under those plans had an exercise price equal to the market value of the Company s common stock on the grant date. Effective January 1, 2006, the Company adopted SFAS No. 123(R) using the modified prospective transition method. Under that transition method, compensation cost recognized in the first quarter of 2006 included: (i) compensation cost for all share-based payments granted prior to, but not yet vested as of January 1, 2006, based on the fair value calculated in accordance with the provisions of SFAS No. 123(R); and (ii) compensation cost for all share-based payments granted in the first quarter of 2006 based on the fair value calculated in accordance with the provisions of SFAS No. 123(R). Results for prior periods were not restated.

As a result of adopting SFAS No. 123(R) on January 1, 2006, the Company recorded a cumulative effect adjustment of approximately $0.4 million pre-tax ($0.2 million after tax, or less than $0.01 per basic and diluted share) on January 1, 2006 for outstanding non-vested share-based compensation grants at December 31, 2005, which is not included in the amounts discussed below. The Company determined that the cumulative effect adjustment was immaterial for presentation purposes and is, therefore, included in Other Operation and Maintenance Expense in the Consolidated Statement of Income. The Company recorded compensation expense of approximately $8.6 million pre-tax ($5.3 million after tax, or $0.06 per basic and diluted share) in 2006 related to the Company s share-based payments.

Prior to the adoption of SFAS No. 123(R), the Company presented all tax benefits of deductions resulting from the exercise of stock options or other share-based payments as operating cash flows in the Consolidated Statements of Cash Flows. SFAS No. 123(R) requires cash flows resulting in tax benefits from tax deductions in excess of the compensation cost recognized for share-based payments (excess tax benefits) to be classified as financing cash flows. The Company recorded an excess tax benefit of approximately $2.8 million in 2006 related to the Company s 2006 share-based payments, which amount will be presented as a financing cash inflow and realized when the Company s 2006 income tax return is completed in 2007. The Company realized an excess tax benefit of approximately $1.4 million in 2006 related to the Company s 2005 share-based payments, which amount was presented as a financing cash inflow and realized when the Company s 2005 income tax return was filed in August 2006. The Company realized an excess tax benefit of approximately $0.8 million during 2005 related to the Company s 2004 share-based payments. The Company did not realize an excess tax benefit during 2004 related to the Company s 2003 share-based payments.

Performance Units

Under the Plans, the Company has issued performance units which represent the value of one share of the Company s common stock. The performance units provide for accelerated vesting if there is a change in control (as defined in the Plans). Each performance unit is subject to forfeiture if the recipient terminates employment with the Company or a subsidiary prior to the end of the three-year award cycle for any reason other than death, disability or retirement. In the event of death, disability or retirement, a participant will receive a prorated payment based on such participant s number of full months of service during the three-year award cycle, further adjusted based on the achievement of the performance goals during the award cycle. The following table is a summary of the terms of the Company s outstanding performance units awarded during 2004, 2005 and 2006.

Condition	Settlement		Vesting Period	SFAS No. 123(R) Classification
Total Shareholder Return	2/3	Stock (A)	3-year cliff	Equity
	1/3	Cash	3-year cliff	Liability
Earnings Per Share	2/3	Stock (A)	3-year cliff	Equity
	1/3	Cash	3-year cliff	Liability

(A) All of the Company s 2006 performance units will be settled in stock.

The performance units granted based on total shareholder return (TSR) are contingently awarded and will be payable in cash or shares of the Company s common stock (other than performance units awarded in 2006, which will be payable only in shares of 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 TSR ranking relative to a peer group of companies. The performance units granted based on earnings per share (EPS) are contingently awarded and will be payable in cash or shares of the Company s common stock (other than performance units awarded in 2006, which will be payable only in shares of common stock) based on the Company s EPS growth over a three-year award cycle compared to a target set at the time of the grant by the Compensation Committee of the Company s Board of Directors. If there is no or only a partial payout for the performance units at the end of the three-year award cycle, the unearned performance units are cancelled. During 2006, 2005 and 2004, respectively, the Company awarded 239,856, 201,794 and 162,591 performance units to certain employees of the Company and its subsidiaries.

Performance Units Total Shareholder Return

The Company recorded compensation expense of approximately $6.5 million pre-tax ($4.0 million after tax) in 2006 related to the performance units based on TSR. The Company recorded compensation expense of approximately $0.6 million pre-tax ($0.4 million after tax) and $3.6 million pre-tax ($2.2 million after tax) in 2005 and 2004, respectively, related to the performance units based on TSR. The fair value of the performance units based on TSR was estimated on the grant date using a lattice-based valuation model that factors in information, including the expected dividend yield, expected price volatility, risk-free interest rate and the probable outcome of the market condition, over the expected life of the performance units. Compensation expense for the performance units settled in stock is a fixed amount determined at the grant date fair value and is recognized over the three-year award cycle regardless of whether performance units are awarded at the end of the award cycle. Compensation expense for the performance units settled in cash is based on the change in the fair value of the performance units for each reporting period. This liability for the performance units will be remeasured at each reporting date until the date of settlement. Dividends are not accrued or paid during the performance period and, therefore, are not included in the fair value calculation. Expected price volatility is based on the historical volatility of the Company s common stock for the past three years and was simulated using the Geometric Brownian Motion process. The risk-free interest rate for the performance unit grants is based on the three-year U.S. Treasury yield curve in effect at the time of the grant. The expected life of the units is based on the non-vested period since inception of the three-year award cycle. There are no post-vesting restrictions related to the Company s performance units based on TSR. The fair value of the performance units based on TSR was calculated based on the following assumptions at the grant date.

	2006	2005	2004
Expected dividend yield	4.9%	5.3%	6.5%
Expected price volatility	16.8%	22.3%	23.0%
Risk-free interest rate	4.66%	3.28%	2.47%
Expected life of units (in years)	2.85	2.85	2.94
Fair value of units granted	$ 22.93	$ 21.56	$ 20.10

The fair value of the performance units based on TSR which are settled in cash was remeasured at December 31, 2006 based on the following assumptions.

	2005

Expected dividend yield	4.0%
Expected price volatility	15.8%
Risk-free interest rate	4.96%
Expected life of units (in years)	1.00
Fair value of units at 12/31/06	$ 62.62

A summary of the activity for the Company s performance units based on TSR at December 31, 2006 and changes during 2006 are summarized in the following table. Following the end of a three-year performance period, payout of the performance units based on TSR is determined by the Company s TSR for such period compared to a peer group and payout requires the approval of the Compensation Committee of the Company s Board of Directors. Payouts, if any, are made in two-thirds stock and one-third cash (other than payouts of performance units awarded in 2006, which will be made only in common stock) and are considered made when the payout is approved by the Compensation Committee.

(dollars in millions)	Number of Units	Stock Conversion Ratio (A)	Aggregate Intrinsic Value
Units Outstanding at 12/31/05	385,536	1 : 1	
Granted (B)	179,896	1 : 1	
Converted	(111,235)	1 : 1	$ 4.3
Forfeited	(13,934)	1 : 1	
Units Outstanding at 12/31/06	440,263	1 : 1	$ 32.5
Units Fully Vested at 12/31/06 (C)	132,845	1 : 1	$ 9.3

(A) One performance unit = one share of the Company s common stock.

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

(C) These performance units awarded in 2004 became fully vested at December 31, 2006 and if certified by the Compensation Committee of the Company s Board of Director s will be converted in February 2007.

A summary of the activity for the Company s non-vested performance units based on TSR at December 31, 2006 and changes during 2006 are summarized in the following table:

	Number of Units	Weighted-Average Grant Date Fair Value
Units Non-Vested at 12/31/05	274,301	$ 20.84
Granted (D)	179,896	$ 22.93
Vested (E)	(132,845)	$ 20.10
Forfeited	(13,934)	$ 22.11
Units Non-Vested at 12/31/06 (F)	307,418	$ 22.33

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

(E) These performance units awarded in 2004 became fully vested at December 31, 2006 and if certified by the Compensation Committee of the Company s Board of Director s will be converted in February 2007.

(F) Of the 307,418 performance units not vested at December 31, 2006, 267,650 performance units are assumed to vest at the end of the applicable vesting period.

At December 31, 2006, there was approximately $3.7 million in unrecognized compensation cost related to non-vested performance units based on TSR which is expected to be recognized over a weighted-average period of 1.61 years.

Performance Units Earnings Per Share

The Company recorded compensation expense of approximately $2.0 million pre-tax ($1.2 million after tax) in 2006 related to the performance units based on EPS. The Company recorded compensation expense of approximately $0.5 million pre-tax ($0.3 million after tax) in 2005 related to the performance units based on EPS. No compensation expense related to performance units based on EPS was recognized in 2004 as the 2004 performance units did not have an EPS component. The fair value of the performance units based on EPS is based on grant date fair value which is equivalent to the price of one share of the Company s common stock on the date of grant. The fair value of performance units based on EPS varies as the number of performance units that will vest is based on the grant date fair value of the units and the probable outcome of the performance condition. The Company reassesses at each reporting date whether achievement of the performance condition is probable and accrues compensation expense if and when achievement of the performance condition is probable. As a result, the compensation expense recognized for these performance units can vary from period to period. There are no post-vesting restrictions related to the Company s performance units based on EPS. The grant date fair value of the 2005 and 2006 performance units was $23.78 and $28.00, respectively.

A summary of the activity for the Company s performance units based on EPS at December 31, 2006 and changes during 2006 are summarized in the following table. Following the end of a three-year performance period, payout of the performance units based on EPS growth is determined by the Company s growth in EPS for such period compared to a target set at the beginning of the three-year period by the Compensation Committee of the Company s Board of Directors and payout requires the approval of the Compensation Committee. Payouts, if any, are made in two-thirds stock and one-third cash (other than payouts of performance units awarded in 2006, which will be made only in common stock) and are considered made when approved by the Compensation Committee.

(dollars in millions)	Number of Units	Stock Conversion Ratio (B)	Aggregate Intrinsic Value
Units Outstanding at 12/31/05	46,531	1:1	
Granted (A)	59,960	1:1	
Forfeited	(4,032)	1:1	
Units Outstanding at 12/31/06	102,459	1:1	$ 8.2

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

(B) These performance units awarded in 2004 became fully vested at December 31, 2006 and if certified by the Compensation Committee of the Company s Board of Director s will be converted in February 2007.

A summary of the activity for the Company s non-vested performance units based on EPS at December 31, 2006 and changes during 2006 are summarized in the following table:

	Number of Units	Weighted-Average Grant Date Fair Value
Units Non-Vested at 12/31/05	46,531	$ 23.78
Granted (C)	59,960	$ 28.00
Forfeited	(4,032)	$ 26.40
Units Non-Vested at 12/31/06 (D)	102,459	$ 26.15

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

(D) Of the 102,459 performance units not vested at December 31, 2006, 89,203 performance units are assumed to vest at the end of the applicable vesting period.

At December 31, 2006, there was approximately $2.6 million in unrecognized compensation cost related to non-vested performance units based on EPS which is expected to be recognized over a weighted-average period of 1.7 years.

Stock Options

The Company recorded compensation expense of approximately $0.1 million pre-tax (less than $0.1 million after tax) in 2006 related to stock options. During 2006 and 2005, no stock options were granted under the 2003 Plan. During 2004, 380,400 stock options were granted under the 2003 Plan. Compensation expense for the non-vested stock options at December 31, 2005 was a fixed amount determined at the grant date fair value and was recognized over the remaining vesting period during 2006. No compensation expense related to stock options was recognized in 2005 or 2004 as all options granted under those plans had an exercise price equal to the market value of the Company s common stock on the grant date. The Company accounts for stock option grants as separate grants. The 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. Each option is subject to forfeiture if the recipient terminates employment with the Company or a subsidiary for any reason other than death, disability or retirement. Dividends are not paid or accrued on unexercised options. The options provide for accelerated vesting if there is a change in control (as defined in the Plans). The fair value of each option grant under the Plans is estimated on the grant date using the Black-Scholes option pricing model that factors in information, including the expected dividend yield, expected price volatility and risk-free interest rate. The fair value was $2.05 at the grant date for the stock options that are not fully vested at December 31, 2006 and was calculated based on the following assumptions at the grant date.

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

A summary of the activity for the Company s options at December 31, 2006 and changes during 2006 are summarized in the following table:

(dollars in millions)	Number of Options	Weighted-Average Exercise Price	Aggregate Intrinsic Value	Weighted-Average Remaining Contractual Term
Options Outstanding at 12/31/05	2,139,376	$ 22.20		
Exercised	(634,973)	$ 22.79	$ 7.2	
Expired	(15,200)	$ 26.58		
Forfeited	(3,601)	$ 21.41		
Options Outstanding at 12/31/06	1,485,602	$ 21.90	$26.90	4.86 years
Options Fully Vested and Exercisable at 12/31/06	1,394,220	$ 21.79	$25.40	4.74 years

A summary of the activity for the Company s non-vested options at December 31, 2006 and changes during 2006 are summarized in the following table:

	Number of Options	Weighted-Average Grant Date Fair Value
Options Non-Vested at 12/31/05	404,398	$ 1.95
Vested	(294,215)	$ 2.02
Expired	(15,200)	$ ---
Forfeited	(3,601)	$ 1.99
Options Non-Vested at 12/31/06 (A)	91,382	$ 2.05

(A) All of the 91,382 stock options not vested at December 31, 2006 vested in January 2007.

At December 31, 2006, there was no unrecognized compensation cost related to non-vested options, which became fully vested in January 2007.

The Company issues new shares to satisfy stock option exercises. The Company received approximately $14.5 million in 2006 related to exercised stock options. The Company recorded an excess tax benefit of approximately $2.8 million in 2006 related to the Company s 2006 share-based payments, which amount will be presented as a financing cash inflow and realized when the Company s 2006 income tax return is completed in 2007. The Company realized an excess tax benefit of approximately $1.4 million in 2006 related to the Company s 2005 share-based payments, which amount was presented as a financing cash inflow and realized when the Company s 2005 income tax return was filed in August 2006. The Company realized an excess tax benefit of approximately $0.8 million during 2005 related to the Company s 2004 share-based payments. The Company did not realize a excess tax benefit during 2004 related to the Company s 2003 share-based payments.

4. Asset Retirement Obligations

In accordance with SFAS No. 143 for periods subsequent to the initial measurement of an asset retirement obligations (ARO), an entity shall recognize period-to-period changes in the liability for an ARO resulting from: (i) the passage of time; and (ii) revisions to either the timing or the amount of the original estimate of undiscounted cash flows. During the second quarter of 2006, the Company reviewed its initial ARO valuations and determined that there were changes in the liability of the ARO related to power plant structure legal obligations resulting from revisions to the amount of the original estimate of undiscounted cash flows. As a result, an ARO of approximately $1.0 million was recognized as an increase in the carrying amount of the liability for an ARO and an increase in the related asset retirement cost capitalized as part of the carrying amount of the related long-lived asset with no effect on net income. There were no changes made to previously recorded ARO s during the last six months of 2006. Also, in the fourth quarter of 2006, OG&E recorded an additional ARO for approximately $0.9 million related to its Centennial wind farm. Beginning January 1, 2007, OG&E will amortize the remaining value of the related ARO asset over the estimated remaining life of 99 years. The Company has also identified other ARO s that have not been recorded because the Company determined that these assets have indefinite lives primarily related to Enogex s processing plants and compression sites.

5. Loss on Retirement and Asset Retirement Obligation of Fixed Assets

OG&E had a power supply contract with a large industrial customer which expired June 1, 2006. In conjunction with the expiration of this contract, OG&E evaluated options to utilize the assets dedicated to that customer, which resulted in the decision to retire these assets as of June 30, 2006. The carrying amount of these assets at June 30, 2006 was approximately $6.8 million, which was recorded as a pre-tax loss during the second quarter of 2006. This loss was included in Other Expense in the Consolidated Statement of Income. Also, as part of the settlement of the ARO for these assets, OG&E recorded a reduction to the previously recorded ARO for these assets of approximately $0.9 million in 2006 due to an agreement with a third party to provide removal and remediation services. This reduction is included in Other Expense in the Consolidated Statement of Income.

6. Asset Sales

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 response to this notification, the Company recognized, during the third quarter of 2004, a pre-tax impairment loss of approximately $8.6 million in the Natural Gas Pipeline segment related to Enogex natural gas pipeline assets that were used to provide service to this customer. In December 2004, the Company received notification that all of this customers plants in West Texas were shut down and service was no longer required. In November 2006, Enogex sold the four non-contiguous pipeline asset segments for approximately $1.0 million. Enogex recognized a pre-tax gain of approximately $1.0 million in the fourth quarter of 2006 related to the sale of these assets. These assets were part of the Natural Gas Pipeline segment.

7. 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 2006 and 2005, 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 in late 2005 protected against the variability of future interest payments of long-term debt that was issued by OG&E in January 2006 and the treasury lock agreement in November 2006 is to protect against the variability of future interest payments of long-term debt that is expected to be issued during the first half of 2007.

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 are settled on a net basis daily through margin accounts with a clearing broker and, therefore, are recorded at fair value on a net basis in Other Current Assets in the Consolidated Balance Sheets. 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: (i) commodity contracts for the purchase and sale of natural gas by its subsidiaries, Enogex Inc. and Enogex Gas Gathering, L.L.C.; (ii) commodity contracts for the sale of natural gas liquids produced by its subsidiary, Enogex Products Corporation (Products); (iii) electric power contracts by OG&E; and (iv) fuel procurement by OG&E.

At December 31, 2006 and 2005, the Company had no outstanding interest rate swap agreements. At December 31, 2006, OG&E s treasury lock agreement has been designated as a cash flow hedge under SFAS No. 133. At December 31, 2005, OG&E had two separate treasury lock agreements designated as cash flow hedges under SFAS No. 133, which were terminated on January 6, 2006 after OG&E issued long-term debt. 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.

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 or against the brokerage deposits in Other Current Assets. 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.

In accordance with FASB Interpretation No. 39 (As Amended), Offsetting of Amounts Related to Certain Contracts an interpretation of APB Opinion No. 10 and FASB Statement No. 105, fair value amounts recognized for forward, interest rate swap, currency swap, option and other conditional or exchange contracts executed with the same counterparty under a master netting arrangement may be offset. The reporting entity s choice to offset or not must be applied consistently. A master netting arrangement exists if the reporting entity has multiple contracts, whether for the same type of conditional or exchange contract or for different types of contracts, with a single counterparty that are subject to a contractual agreement that provides for the net settlement of all contracts through a single payment in a single currency in the event of default on or termination of any one contract. Offsetting the fair values recognized for forward, interest rate swap, currency swap, option and other conditional or exchange contracts outstanding with a single counterparty results in the net fair value of the transactions being reported as an asset or a liability in the consolidated balance sheet.

In the Company s Consolidated Balance Sheets at December 31, 2006 and 2005, the fair value of transactions with the same counterparty is presented on a gross basis, consistent with past practice. However, OERI has energy trading contracts with set off provisions with various counterparties. If these transactions with the same counterparty were presented on a net basis in the Consolidated Balance Sheets, Price Risk Management assets and liabilities would be approximately $40.0 million and $6.7 million at December 31, 2006, respectively, and would be approximately $98.0 million and $92.8 million at December 31, 2005, respectively.

8. Enogex Discontinued Operations

In April 2005, Enogex Compression Company, LLC (Enogex Compression) received an unsolicited offer to buy its interest in Enerven Compression Services, LLC (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 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 Enogex Arkansas Pipeline Corporation (EAPC), which held the 75 percent interest in the NOARK Pipeline System Limited Partnership. This sale was completed on October 31, 2005. The Company received approximately $177.4 million in cash proceeds and recognized an after tax gain of approximately $36.7 million from the sale of this business in the fourth quarter of 2005. 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, was used, among other things, to reduce short-term debt levels and fund capital expenditures.

In March 2006, Enogex announced that its wholly-owned subsidiary, Gathering, had entered into an agreement to sell certain gas gathering assets in the Kinta, Oklahoma, area. The Gathering assets included in the transaction were approximately 568 miles of gas gathering pipeline and 22 compressor units with current volumes of approximately 145 million cubic feet per day, all in eastern Oklahoma. The sale price was approximately $93 million. This transaction closed on May 1, 2006 and Enogex recorded an after tax gain of approximately $34.1 million during the second quarter of 2006. The proceeds from the sale, were used, among other things, to reduce short-term debt levels and fund capital expenditures.

The Consolidated Financial Statements of the Company have been reclassified to reflect Enogex Compression s sale of its Enerven interest, Enogex s sale of its EAPC interest and Gathering s gas gathering assets in Kinta, Oklahoma, all of which were part of the Natural Gas Pipeline segment, as discontinued operations. Accordingly, revenues, costs and expenses and cash flows of Enerven, EAPC and the Gathering assets that were sold 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. Enogex Compression s sale of its Enerven interest and Enogex s sale of its EAPC interest were completed during 2005 and, therefore, there are no results of operations for these transactions during 2006. Summarized financial information for the discontinued operations as of December 31 is as follows:

CONSOLIDATED STATEMENTS OF INCOME DATA

Year ended December 31 *(In millions)*	**2006**	2005	2004
Operating revenues from discontinued operations	**$ 9.4**	$ 106.0	$ 120.1
Income from discontinued operations before taxes	**59.1**	84.2	18.6

9. 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)*	**2006**	2005	2004
NON-CASH INVESTING AND FINANCING ACTIVITIES			
Change in fair value of long-term debt due to interest rate swaps	**$ ---**	$ (7.8)	$ 0.3
Power plant long-term service agreement	**---**	---	6.0
Issuance of common stock	**---**	---	2.2
SUPPLEMENTAL CASH FLOW INFORMATION			
Cash Paid During the Period for			
Interest (net of interest capitalized of $5.4, $2.2, $1.7)	**$ 85.5**	$ 95.9	$ 85.2
Income taxes (net of income tax refunds)	**122.7**	42.0	37.4

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10. Income Taxes

The items comprising income tax expense are as follows:

Year ended December 31 *(In millions)*	**2006**	2005	2004
Provision (Benefit) for Current Income Taxes from Continuing Operations			
Federal	**$ 96.0**	$ 43.0	$ 19.3
State	**(7.4)**	5.0	2.2
Total Provision for Current Income Taxes from Continuing Operations	**88.6**	48.0	21.5
Provision for Deferred Income Taxes, net from Continuing Operations			
Federal	**35.4**	26.4	50.4
State	**1.9**	---	4.3
Total Provision for Deferred Income Taxes, net from Continuing Operations	**37.3**	26.4	54.7
Deferred Federal Investment Tax Credits, net	**(5.0)**	(5.1)	(5.2)
Income Taxes Relating to Other Income and Deductions	**(0.4)**	(0.7)	2.4
Total Income Tax Expense from Continuing Operations	**$ 120.5**	$ 68.6	$ 73.4

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 continues to amortize its federal investment tax credits on a ratable basis throughout the year. This ratable amortization results in a larger percentage reconciling item related to these credits during the first quarter when the Company historically experiences decreased book income. The following schedule reconciles the statutory federal tax rate to the effective income tax rate:

Year ended December 31	**2006**	2005	2004
Statutory federal tax rate	**35.0%**	35.0%	35.0%
State income taxes, net of federal income tax benefit	**2.8**	1.5	2.0
Amortization of net unfunded deferred taxes	**0.7**	1.0	1.0
Tax credits, net	**(1.4)**	(2.2)	(2.4)
ESOP dividends	**(0.9)**	(1.8)	---
Medicare Part D subsidy	**(0.7)**	(1.2)	---
Excess deferred taxes (A)	**---**	(2.3)	---
Other	**(0.7)**	(0.1)	(1.5)
Effective income tax rate as reported	**34.8%**	29.9%	34.1%

(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 2.3 percent.

In connection with the filing in the third quarter of 2003 of the Company s consolidated income tax returns for 2002, OG&E elected to change its tax method of accounting related to the capitalization of costs for self-constructed assets to another method prescribed in the Income Tax regulations. The accounting method change was for income tax purposes only. For financial accounting purposes, the only change was recognition of the impact of the cash flow generated by accelerating income tax deductions. This was 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 were refunded. 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. The Company s current IRS examination process, which was completed in the second quarter of 2006, identified this change in method of accounting as an issue under examination. As a result of their examination, the IRS disagreed with the change OG&E made in 2002 and determined that OG&E should change its tax method of accounting for the capitalization of costs for self-constructed assets to another method prescribed in the Income Tax regulations. The Company filed a formal protest with the IRS on July 21, 2006 and requested a hearing with the IRS to review the IRS s determination that the tax accounting method OG&E elected in 2002 was not appropriate. On August 17, 2006, the Company made a deposit with the IRS in anticipation that a portion of prior year deductions will be disallowed. The deposit enabled OG&E to cease accruing interest effective August 17, 2006. The impact of this matter on future cash flows is uncertain but could be material. The Company cannot predict either the final outcome or the timing of the resolution of this matter. During 2005 and 2006, OG&E recorded approximately $3.5 million in 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.

The Company follows the provisions of SFAS No. 109 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, 2006 and 2005, respectively, are as follows:

December 31 *(In millions)*	**2006**	2005
Current Accumulated Deferred Tax Assets		
Accrued vacation	**$ 6.2**	$ 6.3
Uncollectible accounts	**1.8**	1.4
Capitalized indirect construction costs	**1.7**	1.7
Provision for rate refund	**0.5**	2.7
Other	**0.4**	2.2
Total Current Accumulated Deferred Tax Assets	**$ 10.6**	$ 14.3
Non-Current Accumulated Deferred Tax Liabilities		
Accelerated depreciation and other property related differences	**$ 816.8**	$ 826.4
Regulatory asset	**95.2**	---
Income taxes refundable to customers, net	**16.7**	12.7
Bond redemption-unamortized costs	**6.5**	6.9
Other	**19.3**	0.7
Total Non-Current Accumulated Deferred Tax Liabilities	**954.5**	846.7
Non-Current Accumulated Deferred Tax Assets		
Company pension plan	**(26.2)**	(13.6)
Postretirement medical and life insurance benefits	**(55.5)**	(15.3)
Deferred federal investment tax credits	**(7.0)**	(8.6)
Other	**(6.6)**	(2.1)
Total Non-Current Accumulated Deferred Tax Assets	**(95.3)**	(39.6)
Non-Current Accumulated Deferred Income Tax Liabilities, net	**$ 859.2**	$ 807.1

The Company has an Oklahoma investment tax credit carryover of approximately $3.7 million. These Oklahoma credit carryover amounts will begin expiring in the year 2017. During 2006, additional Oklahoma tax credits of approximately $5.1 million were generated by OG&E and Enogex. The Company believes that, based on current projections, the entire $8.8 million of these state tax credit amounts will be fully utilized in 2007.

11. Common Stock

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 years ended December 31, 2006 and 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. Also, as part of the

DRIP/DSPP, the Company issued 242,003 shares of common stock at no discount during the year ended December 31, 2004.

For the years ended December 31, 2006, 2005 and 2004, respectively, there were 738,426, 606,802 and 392,686 shares of new common stock issued pursuant to the Company s Stock Incentive Plan, related to exercised stock options and payouts of earned performance units. At December 31, 2006, there were 13,010,588 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.

12. 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)*	**2006**	2005	2004
Average Common Shares Outstanding			
Basic average common shares outstanding	**91.0**	90.3	88.0
Effect of dilutive securities:			
Employee stock options and unvested stock grants	**0.3**	0.2	0.3
Contingently issuable shares (performance units)	**0.8**	0.3	0.2
Diluted average common shares outstanding	**92.1**	90.8	88.5

For the years ended December 31, 2006, 2005 and 2004, respectively, approximately 0.1 million shares, 0.2 million shares and 0.6 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.

13. Long-Term Debt

A summary of the Company s long-term debt is included in the Consolidated Statements of Capitalization. At December 31, 2006, the Company is in compliance with all of its debt agreements.

Long-Term Debt with Optional Redemption Provisions

OG&E s $125.0 million principal amount 6.65 percent Senior Notes (Senior Notes) due July 15, 2027, are repayable on July 15, 2007, at the option of the holders, at 100 percent of the principal amount, together with accrued and unpaid interest to July 15, 2007. Only holders who submit requests for repayment between May 15, 2007 and June 15, 2007 are entitled to such repayments. In accordance with SFAS No. 6, Classification of Short-Term Obligations Expected to Be Refinanced, OG&E reclassified the Senior Notes from long-term debt due within one year to long-term debt at December 31, 2006 due to OG&E having sufficient long-term liquidity in place as a result of increasing its revolving credit agreement to $400.0 million in December 2006. Also, based on where the Senior Notes have recently traded, OG&E does not believe it is probable that this option will be exercised by the note holders.

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
3.11% - 4.05%	Garfield Industrial Authority, January 1, 2025	**$ 47.0**
3.20% - 4.13%	Muskogee Industrial Authority, January 1, 2025	**32.4**
3.03% - 4.06%	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 long-term liquidity to meet these obligations.

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 2009 or 2011.

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.

14. 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 $30.0 million at December 31, 2005 at a weighted-average interest rate of 4.421 percent. There was no short-term debt outstanding at December 31, 2006. In accordance with SFAS No. 6, $220.0 million of commercial paper was classified as long-term debt at December 31, 2005 as OG&E planned to refinance this amount. Subsequently, OG&E issued $220 million of long-term debt in January 2006 and repaid the outstanding commercial paper and bank borrowings. The following table shows the Company s revolving credit agreements and available cash at December 31, 2006.

Revolving Credit Agreements and Available Cash *(In millions)*

Entity	Amount Available	Amount Outstanding	Weighted-Average Interest Rate	Maturity
OGE Energy Corp. (A)	$ 600.0	$ ---	---	December 6, 2011 (C)
OG&E (B)	400.0	---	---	December 6, 2011 (C)
	1,000.0	---	---	
Cash	47.9	N/A	N/A	N/A

Total	$ 1,047.9	$ ---	---

(A) This bank facility is available to back up the Company s commercial paper borrowings and to provide revolving credit borrowings. This bank facility c
(B) This bank facility is available to back up OG&E s commercial paper borrowings and to provide revolving credit borrowings. At December 31, 2006, O
(C) In December 2006, the Company and OG&E amended and restated their revolving credit agreements to total in the aggregate $1.0 billion, $600 million

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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 $800 million in short-term borrowings at any one time for a two-year period beginning January 1, 2007 and ending December 31, 2008.

15. Retirement Plans and Postretirement Benefit Plans

In September 2006, the FASB issued SFAS No. 158 which requires an employer to: (i) recognize the overfunded or underfunded status of a defined benefit postretirement plan (other than a multiemployer plan) as an asset or liability in its statement of financial position and to recognize changes in that funded status in the year in which the changes occur through comprehensive income of a business entity; and (ii) to measure the fair value of the funded status of a plan as of the date of its year-end statement of financial position, with limited exceptions. The requirement to initially recognize the funded status of the defined benefit postretirement plan and the disclosure requirements are effective for the year ended December 31, 2006 for the Company. The requirement to measure plan assets and benefit obligations at fair value in accordance with SFAS No. 157 as of the date of the employer s fiscal year-end statement of financial position is effective for fiscal years ending after December 15, 2008. SFAS No. 158 also requires additional disclosures for defined benefit pension plans and other defined benefit postretirement plans.

Defined Benefit Pension Plan

All eligible employees of the Company and participating affiliates 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, Employers Accounting for Pensions, 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 2006 and 2005, the Company made contributions to its pension plan of approximately $90.0 million and $32.0 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. In August 2006, legislation was passed that changed the funding requirement for single- and multi-employer defined benefit pension plans as discussed below. During 2007, the Company may contribute up to $50 million to its pension 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 regulatory funding requirement specified by the Employee Retirement Income Security Act of 1974, as amended.

At December 31, 2006, the projected benefit obligation and fair value of assets of the Company s pension plan and restoration of retirement income plan was approximately $585.0 million and $519.4 million, respectively, for an underfunded status of approximately $65.6 million. The above amounts have been recorded in Accrued Pension and Benefit Obligations with the offset in Accumulated Other Comprehensive Loss (except OG&E s portion which is recorded as a regulatory asset as discussed in Note 1) in the Company s Consolidated Balance Sheet. The entry did not impact the results of operations in 2006 and did not require a usage of cash and is therefore excluded from the Consolidated Statement of Cash Flows. The amounts in Accumulated Other Comprehensive Loss and as a regulatory asset represent a net periodic benefit cost to be recognized in the Consolidated Statements of Income in future periods.

During 2005, the Company made contributions to the pension plan that exceeded amounts previously recognized as net periodic pension expense and recorded a net prepaid benefit obligation at December 31, 2005 of approximately $88.9 million. At December 31, 2005, the Company s projected pension benefit obligation exceeded the fair value of the pension plan assets by approximately $154.6 million. 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 at December 31, 2005. 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 and did not require a usage of cash and is therefore excluded from the Consolidated Statement 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 benefit cost to be recognized in the Consolidated Statements of Income in future periods.

In accordance with SFAS No. 88, Employer s Accounting for Settlements and Curtailments of Defined Benefit Pension Plans and for Termination Benefits, a one-time settlement charge is required to be recorded by an organization when lump sum payments or other settlements that relieve the organization from the responsibility for the pension benefit obligation during a plan year exceed the service cost and interest cost components of the organization s net periodic pension cost. During 2006, the Company experienced an increase in both the number of employees electing to retire and the amount of lump sum payments to be paid to such employees upon retirement in 2006. As a result, the Company recorded a pension settlement charge for 2006 of approximately $17.1 million in the fourth quarter of 2006. The pension settlement charge did not require a cash outlay by the Company and did not increase the Company s total pension expense over time, as the charge was an acceleration of costs that otherwise would have been recognized as pension expense in future periods. OG&E s Oklahoma jurisdictional portion of this charge was recorded as a regulatory asset (see Note 1 for a further discussion).

Pension Plan Costs and Assumptions

On August 17, 2006, President Bush signed The Pension Protection Act of 2006 (the Pension Protection Act) into law. The Pension Protection Act makes changes to important aspects of qualified retirement plans. Among other things, it introduces a new funding requirement for single- and multi-employer defined benefit pension plans, provides legal certainty on a prospective basis for cash balance and other hybrid plans and addresses contributions to defined contribution plans, deduction limits for contributions to retirement plans and investment advice provided to plan participants. The Company is currently analyzing the impact of the Pension Protection Act on its pension plans.

Plan Investments, Policies and Strategies

The pension 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, 2006 and 2005:

December 31	**2006**	2005
Equity securities	**64 %**	59 %
Debt securities	**34 %**	36 %
Other	**2 %**	5 %
Total	**100 %**	100 %

The pension 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 Employee 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 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

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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 Internal Revenue Code (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.

At December 31, 2006, the accumulated postretirement benefit obligation and fair value of assets of the Company s postretirement benefit plans was approximately $225.4 million and $74.0 million, respectively, for an underfunded status of approximately $151.4 million. The above amounts have been recorded in Accrued Pension and Benefit Obligations with the offset in Accumulated Other Comprehensive Loss (except OG&E s portion which is recorded as a regulatory asset as discussed in Note 1) in the Company s Consolidated Balance Sheet. The entry did not impact the results of operations in 2006 and did not require a usage of cash and is therefore excluded from the Consolidated Statement of Cash Flows. The amounts in Accumulated Other Comprehensive Loss and as a regulatory asset represent a net periodic benefit cost to be recognized in the Consolidated Statements of Income in future periods.

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:

Obligations and Funded Status

	Pension Plan and Restoration of Retirement Income Plan		Postretirement Benefit Plans	
December 31 *(In millions)*	**2006**	2005	**2006**	2005

Change in Benefit Obligation				
Beginning obligations	**$ (594.0)**	$ (548.2)	**$ (208.2)**	$ (192.3)
Service cost	**(20.4)**	(19.1)	**(3.7)**	(3.2)
Interest cost	**(30.8)**	(30.3)	**(11.9)**	(10.5)
Participants contributions	**---**	---	**(5.0)**	(3.9)
Actuarial losses	**(14.9)**	(38.9)	**(12.1)**	(12.0)
Benefits paid	**75.1**	42.5	**15.5**	13.7
Ending obligations	**(585.0)**	(594.0)	**(225.4)**	(208.2)
Change in Plans Assets				
Beginning fair value	**439.4**	424.9	**67.2**	64.0
Actual return on plans assets	**64.7**	23.9	**8.4**	4.6
Employer contributions	**90.4**	33.1	**8.9**	8.4
Participants contributions	**---**	---	**5.0**	3.9
Benefits paid	**(75.1)**	(42.5)	**(15.5)**	(13.7)
Ending fair value	**519.4**	439.4	**74.0**	67.2
Funded status at end of year	**$ (65.6)**	$ (154.6)	**$ (151.4)**	$ (141.0)

Incremental Effect of Applying SFAS No. 158 on Individual Line Items in the Consolidated Balance Sheet at December 31, 2006

	Before Application of SFAS		After Application of SFAS
December 31 *(In millions)*	No. 158	Adjustments	No. 158
Regulatory asset SFAS 158	$ ---	$ 231.1	$ 231.1
Intangible asset unamortized prior service cost	3.2	(3.2)	---
Prepaid benefit obligation	129.7	(129.7)	---
Total deferred charges and other assets	237.0	98.2	335.2
Accrued pension and benefit obligations:			
Defined pension plan	7.5	58.1	65.6
Defined postretirement benefit plans	57.9	93.5	151.4
Accumulated deferred income taxes	881.6	(22.4)	859.2
Total deferred credits and other liabilities	1,149.7	129.2	1,278.9
Accumulated other comprehensive loss	3.0	(31.0)	(28.0)
Total stockholders equity	1,634.8	(31.0)	1,603.8

Amounts recognized in the Consolidated Balance Sheets consist of:

December 31 *(In millions)*	Pension Plan and Restoration of Retirement Income Plan 2005	Postretirement Benefit Plans 2005
Prepaid benefit obligation	$ 90.2	$ ---
Accrued pension and benefit obligations	(182.8)	(43.3)
Intangible asset - unamortized prior service cost	32.8	---
Accumulated deferred tax asset	57.5	---
Accumulated other comprehensive loss, net of tax	91.2	---
Net amount recognized	$ 88.9	$ (43.3)

Net Periodic Benefit Cost

	Pension Plan and Restoration of Retirement Income Plan			Postretirement Benefit Plans		
Year ended December 31*(In millions)*	**2006**	2005	2004	**2006**	2005	2004
Service cost	**$ 20.4**	$ 19.1	$ 16.9	**$ 3.7**	$ 3.2	$ 3.0
Interest cost	**30.8**	30.3	29.7	**11.9**	10.5	11.1
Return on plan assets	**(38.4)**	(34.2)	(31.6)	**(5.6)**	(5.5)	(5.5)
Amortization of transition obligation	**---**	---	---	**2.7**	2.7	2.7
Amortization of net loss	**16.7**	14.7	11.9	**8.7**	5.0	4.9
Amortization of recognized prior service cost	**5.9**	6.3	6.3	**2.1**	2.1	2.1
Settlement (A)	**17.1**	---	---	**---**	---	---
Net periodic benefit cost (B)	**$ 52.5**	$ 36.2	$ 33.2	**$ 23.5**	$ 18.0	$ 18.3

(A) Approximately $13.7 million of the $17.1 million settlement charge relates to OG Es Oklahoma jurisdictional portion, which has been recorded as a regulatory asset (see Note 1 for a further discussion).

(B) The capitalized portion of the net periodic pension benefit cost was approximately $7.6 million, $9.3 million and $8.4 million at December 31, 2006, 2005 and 2004, respectively. The capitalized portion of the net periodic postretirement benefit cost was approximately $5.0 million, $4.7 million and $5.0 million at December 31, 2006, 2005 and 2004, respectively.

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Rate Assumptions

	Pension Plan			Postretirement Benefit Plans		
Year ended December 31	**2006**	2005	2004	**2006**	2005	2004
Discount rate	**5.75%**	5.50%	5.75%	**5.75%**	5.50%	5.75%
Rate of return on plans assets	**8.50%**	8.50%	8.75%	**8.50%**	8.50%	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%**	9.00%	10.00%
Ultimate trend rate	**N/A**	N/A	N/A	**4.50%**	4.50%	4.50%
Ultimate trend year	**N/A**	N/A	N/A	**2012**	2011	2010

N/A - not applicable

The overall expected rate of return on plan assets assumption remained 8.50 percent in 2005 and 2006 in determining net periodic benefit 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 $61.8 million in 2007, $64.2 million in 2008, $65.3 million in 2009, $64.5 million in 2010, $67.4 million in 2011 and an aggregate of $312.8 million in years 2012 to 2016. 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 eight percent in 2007 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

Year ended December 31 *(In millions)*	**2006**	2005	2004
Effect on aggregate of the service and interest cost components	**$ 2.2**	$ 1.8	$ 1.9
Effect on accumulated postretirement benefit obligations	**29.2**	26.9	24.2

ONE-PERCENTAGE POINT DECREASE

Year ended December 31 *(In millions)*	**2006**	2005	2004
Effect on aggregate of the service and interest cost components	**$ 1.8**	$ 1.5	$ 1.5
Effect on accumulated postretirement benefit obligations	**24.0**	22.0	19.8

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 provided 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 required 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 with respect to its postretirement medical plan will be reduced by approximately $39.7 million as a result of savings to the Company with respect to its postretirement medical plan resulting from the Medicare Act provided subsidy, which will reduce the Company s costs for its postretirement medical plan by approximately $6.5 million annually. The $6.5 million in annual savings is comprised of a reduction of approximately $3.8 million from amortization of the $39.7 million gain due to the reduction of the APBO, a reduction in the interest cost on the APBO of approximately $2.2 million and a reduction in the service cost due to the subsidy of approximately $0.5 million.

The Company expects to pay gross benefits payments related to its postretirement benefit plans, including prescription drug benefits, of approximately $12.1 million in 2007, $12.6 million in 2008, $13.6 million in 2009, $14.6 million in 2010, $15.6 million in 2011 and an aggregate of $89.2 million in years 2012 to 2016. The Company expects to receive federal subsidy receipts provided by the Medicare Act of approximately $1.1 million in 2007, $1.3 million in 2008, $1.4 million in 2009, $1.6 million in 2010, $1.7 million in 2011 and an aggregate of $10.2 million in years 2012 to 2016. The Company did not receive any federal subsidy receipts in 2006.

Defined Contribution Plan

The Company provides a defined contribution savings plan. Each regular full-time employee of the Company or a participating affiliate is eligible to participate in the plan immediately. All other employees of the Company or a participating 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. Participants who have attained age 50 before the close of a year are allowed to make additional contributions referred to as Catch-Up Contributions, subject to the limitations of the Code. The 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, Catch-Up 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 initially 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. Once made, the Company s contribution may be reallocated, at any time, by participants to other available investment options. The Company contributed approximately $6.8 million, $6.7 million and $6.2 million during 2006, 2005 and 2004, 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 as well as offering this plan to be competitive in the marketplace.

Eligible employees who enroll in the plan have the following deferral options: (i) eligible employees may elect to defer up to a maximum of 70 percent of base salary and 100 percent of bonus awards; or (ii) eligible employees may elect a deferral percentage of base salary and bonus awards based on the deferral percentage elected for a year under the defined contribution plan with such deferrals to start when maximum deferrals to the qualified 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

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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.

16. 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 years ended December 31, 2006 and 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 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, 2006, 2005 and 2004.

2006 *(In millions)*	Electric Utility	Natural Gas Pipeline (A)	Other Operations	Intersegment	Total
Operating revenues	**$ 1,745.7**	**$ 2,367.8**	**$ ---**	**$ (107.9)**	**$ 4,005.6**
Cost of goods sold	**950.0**	**2,060.4**	**---**	**(107.9)**	**2,902.5**
Gross margin on revenues	**795.7**	**307.4**	**---**	**---**	**1,103.1**
Other operation and maintenance	**316.5**	**110.0**	**(9.9)**	**---**	**416.6**
Depreciation	**132.2**	**42.3**	**6.9**	**---**	**181.4**
Impairment of assets	**---**	**0.3**	**---**	**---**	**0.3**
Taxes other than income	**53.1**	**16.0**	**3.0**	**---**	**72.1**
Operating income	**293.9**	**138.8**	**---**	**---**	**432.7**
Interest income	**1.9**	**11.1**	**4.4**	**(11.2)**	**6.2**
Allowance for equity funds used during construction	**4.1**	**---**	**---**	**---**	**4.1**
Other income	**4.0**	**7.7**	**4.6**	**---**	**16.3**
Other expense	**9.7**	**0.3**	**6.7**	**---**	**16.7**
Interest expense	**60.1**	**31.8**	**15.3**	**(11.2)**	**96.0**
Income tax expense (benefit)	**84.8**	**48.0**	**(12.3)**	**---**	**120.5**
Income (loss) from continuing operations	**149.3**	**77.5**	**(0.7)**	**---**	**226.1**
Income from discontinued operations	**---**	**36.0**	**---**	**---**	**36.0**
Net income (loss)	**$ 149.3**	**$ 113.5**	**$ (0.7)**	**$ ---**	**$ 262.1**
Total assets	**$ 3,589.7**	**$ 1,323.4**	**$ 1,968.8**	**$ (1,979.9)**	**$ 4,902.0**
Capital expenditures	**$ 411.1**	**$ 67.1**	**$ 8.4**	**$ ---**	**$ 486.6**

(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.

2006 *(In millions)*	Transportation and Storage	Gathering and Processing	Marketing	Eliminations	Total
Operating revenues	**$ 225.9**	**$ 704.3**	**$ 1,941.3**	**$ (503.7)**	**$ 2,367.8**
Operating income	**$ 54.7**	**$ 79.8**	**$ 4.3**	**$ ---**	**$ 138.8**

2005 *(In millions)*	Electric Utility (A)	Natural Gas Pipeline (B)	Other Operations	Intersegment	Total
Operating revenues	$ 1,720.7	$ 4,332.4	$ ---	$ (141.6)	$ 5,911.5
Cost of goods sold	994.2	4,090.4	---	(142.3)	4,942.3
Gross margin on revenues	726.5	242.0	---	0.7	969.2
Other operation and maintenance	309.2	96.6	(10.9)	---	394.9
Depreciation	134.4	40.4	7.8	---	182.6
Taxes other than income	50.7	15.4	3.2	---	69.3
Operating income (loss)	232.2	89.6	(0.1)	0.7	322.4
Interest income	2.6	2.9	1.7	(3.7)	3.5
Other income (loss)	(2.8)	0.8	1.7	---	(0.3)
Other expense	2.5	0.3	2.7	---	5.5
Interest expense	47.2	32.6	14.2	(3.7)	90.3
Income tax expense (benefit)	52.6	20.4	(4.7)	0.3	68.6
Income (loss) from continuing operations	129.7	40.0	(8.9)	0.4	161.2
Income from discontinued operations	---	49.8	---	---	49.8
Net income (loss)	$ 129.7	$ 89.8	$ (8.9)	$ 0.4	$ 211.0
Total assets	$ 3,255.0	$ 1,680.1	$ 1,963.4	$ (1,999.6)	$ 4,898.9
Capital expenditures	$ 249.1	$ 34.7	13.4	$ ---	$ 297.2

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

(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 of kilowatt-hour (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 quarter of 2005 of approximately $3.4 million. In August 2005, the Company determined that OG&E s net income should not be affected by over or under collections on a temporary or permanent basis, and accordingly, any difference at that time was deferred as a regulatory asset to better reflect the purchase power capacity payment reductions and any change in operating and maintenance expense related to cogeneration. Subsequent to August 2005, any over or under collections related to the cogeneration credit rider are reflected as a regulatory asset or liability.

2005 *(In millions)*	Transportation and Storage	Gathering and Processing	Marketing (C)	Eliminations	Total
Operating revenues	$ 246.4	$ 644.5	$ 3,995.3	$ (553.8)	$ 4,332.4
Operating income (loss)	$ 37.3	$ 58.5	$ (6.2)	$ ---	$ 89.6

(C) 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 Consolidated Statement of Income and a corresponding $7.7 million decrease in Current Price Risk Management Assets in the Consolidated Balance Sheet during the three months ended March 31, 2005.

2004 *(In millions)*	Electric Utility	Natural Gas Pipeline (A)	Other Operations	Intersegment	Total
Operating revenues	$ 1,578.1	$ 3,379.9	$ ---	$ (95.4)	$ 4,862.6
Cost of goods sold	914.2	3,118.2	---	(94.7)	3,937.7
Gross margin on revenues	663.9	261.7	---	(0.7)	924.9
Other operation and maintenance	301.9	93.5	(11.2)	---	384.2
Depreciation	122.7	41.1	8.3	---	172.1
Impairment of assets	---	7.8	---	---	7.8
Taxes other than income	47.0	16.0	3.3	---	66.3
Operating income (loss)	192.3	103.3	(0.4)	(0.7)	294.5
Interest income	2.7	3.2	1.3	(2.3)	4.9
Allowance for equity funds used during construction	0.9	---	---	---	0.9
Other income	4.5	4.5	1.5	---	10.5
Other expense	2.3	0.3	2.1	---	4.7
Interest expense	37.5	32.2	23.4	(2.3)	90.8
Income tax expense (benefit)	53.0	29.4	(8.7)	(0.3)	73.4
Income (loss) from continuing operations	107.6	49.1	(14.4)	(0.4)	141.9
Income from discontinued operations	---	11.6	---	---	11.6
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	$ 28.9	$ 8.5	$ ---	$ 428.6

(A) Natural Gas Pipeline s operations consist of three related businesses: Transportation and Storage, Gathering and Processing and Marketing. The follow

2004 *(In millions)*	Transportation and Storage	Gathering and Processing	Marketing	Eliminations	Total
Operating revenues	$ 249.4	$ 524.7	$ 3,056.1	$ (450.3)	$ 3,379.9
Operating income	$ 47.1	$ 46.7	$ 9.5	$ ---	$ 103.3

17. Commitments and Contingencies

Capital Expenditures

The Company s capital expenditures are estimated at approximately: 2007 $568.1 million, 2008 $838.6 million, 2009 $815.9 million, 2010 $659.9 million, 2011 $550.2 million and 2012 $436.0 million. These amounts include capital expenditures of approximately $94.0 million, $278.8 million, $285.7 million, $97.7 million and $34.1 million, respectively, in 2007 through 2011 related to the construction of the proposed Red Rock power plant as discussed in Note 18.

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:

Year ended December 31 *(In millions)*	2007	2008	2009	2010	2011	2012 and Beyond
Operating lease obligations						
OG&E railcars	$ 4.0	$ 3.9	$ 3.8	$ 3.7	$ 36.6	$ ---
Enogex noncancellable operating leases	2.2	1.8	1.3	1.4	1.5	0.4
Total operating lease obligations	$ 6.2	$ 5.7	$ 5.1	$ 5.1	$ 38.1	$ 0.4

Payments for operating lease obligations were approximately $7.6 million, $9.7 million and $9.7 million in 2006, 2005 and 2004, respectively.

OG&E Railcar Lease Agreement

At December 31, 2006, 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 Cogeneration Project, L.P. (PowerSmith) in which OG&E purchases 100 percent of electricity generated by PowerSmith.

During 2006, 2005 and 2004, OG&E made total payments to cogenerators of approximately $162.6 million, $183.8 million and $203.5 million, respectively, of which approximately $94.9 million, $95.5 million and $155.3 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: 2007 $97.6 million, 2008 $96.1 million, 2009 $94.4 million, 2010

$92.6 million and 2011 $90.6 million. The minimum capacity payment amounts for 2008 through 2011 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 $195.1 million, $163.5 million and $166.5 million for the years ended December 31, 2006, 2005 and 2004, respectively. OG&E has entered into purchase commitments of necessary fuel supplies of approximately: 2007 $198.0 million, 2008 $114.1 million, 2009 $105.9 million, 2010 $107.7 million, 2011 - $65.4 million and 2012 and Beyond $23.4 million.

Natural Gas Units

In October 2006, OG&E issued and completed a request for proposal (RFP) for gas supply purchases for periods that began in November 2006 through March 2007, which accounted for approximately eight percent of its projected 2007 natural gas requirements. All of these contracts are tied to various gas price market indices and will expire in 2007. OG&E s remaining 2007 natural gas requirements will be met with additional RFP s in early to mid-2007. OG&E will meet additional natural gas requirements with monthly and daily purchases as required.

Purchased Power

In October 2006, OG&E issued an RFP for firm economy energy purchases during the summer of 2007 and expects to select a supplier in early 2007. Also, in early 2007, OG&E expects to issue an RFP for capacity and/or firm energy purchases for the summer periods of 2008 through 2010 and expects to select a supplier by the early summer of 2007.

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 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. 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 in 2005 and the special master ruled that OG&E and all Enogex parties named in these proceedings should be dismissed. This ruling was appealed to the District Court of Wyoming.

On October 20, 2006, the District Court of Wyoming ruled on Grynberg s appeal, following and confirming the recommendation of the special master dismissing all claims against Enogex Inc., Enogex Services Corp., Transok, Inc. and OG&E, for lack of subject matter jurisdiction. Judgment was entered on November 17, 2006 and Grynberg filed his notice of appeal with the District Court of Wyoming. The defendants filed motions for attorneys fees regarding issues of liability and Rule 11 motions on January 8, 2007. The defendants also filed for other legal costs on December 18, 2006. A hearing on these motions is currently scheduled for April 24, 2007. Grynberg has also filed appeals with the Tenth Circuit Court of Appeals. 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. 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. 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.

Pipeline Rupture

On May 10, 2005, a natural gas pipeline rupture occurred on an Enogex facility within the ANR Pipeline, Inc. plant site in Custer County, near Clinton, Oklahoma, resulting in an explosion and fire. No injuries were reported as a result of the incident. 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 was served with a purported class action which had been filed on February 7, 2005 by Farris Buser and other named plaintiffs in the District Court of Canadian County, Oklahoma. The plaintiffs own royalty interests in certain oil and gas producing properties and 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. On September 19, 2005, the co-defendants, BP America, Inc. and BP America Production Co. (collectively, BP), filed a cross claim against Products seeking indemnification and/or contribution from Products based upon the 1997 sale of a third party interest in one of Products natural gas processing plants. On May 17, 2006, the plaintiffs filed an amended petition against the Enogex companies. The Enogex companies filed a motion to dismiss the amended petition on August 2, 2006. The hearing on the dismissal motion was held on November 20, 2006 and the court denied the Enogex companies motion. The Enogex companies filed an answer to the amended petition and BP s cross claim on January 16, 2007. Based on its investigation to date, the Company believes these claims and cross claims in this lawsuit are without merit and intends to continue vigorously defending this case.

Osterhout Litigation

On June 19, 2006, two OG&E customers brought a putative class action, on behalf of all similarly situated customers, in the District Court of Creek County, Oklahoma, challenging certain charges on OG&E s electric bills. The plaintiffs claim that OG&E improperly charged sales tax based on franchise fee charges paid by its customers. The plaintiffs also challenge certain franchise fee charges, contending that such fees are more than is allowed under Oklahoma law. OG&E s motion for summary judgment was denied by the trial judge. OG&E has filed a writ of prohibition at the Oklahoma

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Supreme Court asking the court to direct the trial court to dismiss the class action suit. At the present time, OG&E believes that this case is without merit and intends to continue vigorously defending this case.

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. Calpine is continuing to operate the plants and request services pursuant to the contracts. The total unpaid amount due to Enogex from Calpine is approximately $0.3 million which has been fully reserved on the Company s books.

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 to 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.

Potential Collateral Requirements

At December 31, 2006 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 $3.3 million of collateral to satisfy its obligation under its financial and physical contracts.

Environmental Laws and Regulations

Approximately $16.5 million and $97.5 million, respectively of the Company s capital expenditures budgeted for 2007 and 2008 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 $84.4 million during 2007 as compared to approximately $60.1 million in 2006. 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 15, 2005, the Environmental Protection Agency (EPA) issued the Clean Air Mercury Rule (CAMR) to limit mercury emissions from coal-fired boilers. On May 31, 2006, the EPA issued a ruling which amended and clarified minor portions of the CAMR. 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 requires each state to adopt the requirements of the federal rule into a state implementation plan. However, the CAMR does not preclude states from developing more stringent mercury reduction requirements. The state of Oklahoma has proposed to incorporate the EPA s CAMR, along with the proposed mercury allowance allocations, into the state implementation program. OG&E is currently participating in the state rulemaking process and anticipates the rulemaking to be completed by the end of 2007. Because rulemaking is in progress, the cost to install any mercury controls is uncertain at this time but is expected to be significant to meet Phase II requirements in 2018. The state implementation plan will also require continuous monitoring of mercury emissions from OG&E s coal-fired boilers beginning in 2009. The cost of the monitoring equipment is estimated at approximately $7.9 million which is expected to be incurred during the years 2007 and 2008. However, the cost to comply with the CAMR monitoring requirements 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 Federal Class I areas. Affected utilities are those which have Best Available Retrofit Technology (BART) eligible sources (sources built between 1962 and 1977). For OG&E these include various generating units at various generating stations. Regulations, however, allow an owner or operator of a BART-eligible source to request and obtain a waiver from BART if modeling shows no significant impact on visibility in nearby Class I areas. Therefore, OG&E initiated a preliminary modeling study that was completed in July 2006. Because the preliminary results indicated a significant impact from OG&E s Sooner, Muskogee, Seminole and Horseshoe Lake generating stations on visibility in Class I areas in both Oklahoma and Arkansas, more detailed modeling is being performed. Based on results of modeling for the Seminole and Horseshoe Lake generating stations, OG&E submitted an application for waiver to the ODEQ on December 1, 2006. The ODEQ and the EPA approvals are required for any waiver; it is not known at this time whether approval will be granted. The ODEQ made a preliminary determination to accept the application for Horseshoe Lake and reject the application for Seminole. OG&E is continuing to discuss the Seminole application with the ODEQ.

OG&E is currently evaluating various control strategies for its generating units. Proposed compliance determinations for affected units must be submitted to the ODEQ by March 30, 2007. The ODEQ will then incorporate OG&E s, as well as other industry s compliance plans, into the state implementation plan which will then be submitted to the EPA. Once the EPA approves the plan, OG&E will have five years to institute any required reductions. OG&E is in the process of determining the extent of pollution control equipment needed to comply with the regulations. OG&E plans to spend approximately $5.4 million during 2007 related to the regional haze project. OG&E currently estimates that it could be required to spend approximately $600 million over a five-year period to install certain equipment such as scrubbers and low nitrogen oxide (NOX) burners at its generating stations. However, this amount could increase or decrease substantially based on the interpretation of the requirements by the ODEQ and the EPA, the availability of alternative control measures to achieve more cost effective visibility improvements, the availability of materials, labor force and the specific design criteria for OG&E s generating units. OG&E expects that any necessary environmental expenditures will qualify as part of a pre-approval plan to handle state and federally mandated environmental upgrades which will be recoverable in Oklahoma from OG&E s retail customers under House Bill 1910, which was enacted into law in May 2005.

Currently, the EPA has designated Oklahoma in attainment with the ambient standard for ozone. However, future elevated readings could lead to redesignation of these areas as non-attainment. Both Tulsa and Oklahoma City have entered into an Early Action Compact with the EPA whereby voluntary measures will be enacted to reduce ozone. This compact expires in December 2007. However, the EPA has proposed continuation through a similar program called Ozone Flex, which both Oklahoma City and Tulsa expect to participate. If either Tulsa or Oklahoma City became non-attainment, reductions in nitrogen oxides emissions from OG&E s generating facilities may be required.

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 that they have completed the demonstration that they do not affect air quality in downwind states and are on target to submit it to the EPA by the May 25, 2007 deadline. Therefore, there should be no significant impact to OG&E as a result of the April 25, 2005 finding.

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

The 1990 Clean Air Act includes an acid rain program to reduce sulfur dioxide (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

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financial impact due to OG&E s earlier decision to burn low sulfur coal. In 2006, 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 February 2006, OG&E sold 6,312 allowances for approximately $8.9 million. See Note 18 for a discussion of the SO2 allowance joint filing made in February 2006 which discusses how the proceeds from the sale of SO2 allowances will be shared between OG&E and its customers for any sales after December 31, 2005.

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 average NOX emissions from its coal-fired boilers for 2006 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 the ODEQ determines that such NOX emissions are contributing to regional haze or 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, 2006, 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 2006. The fees for 2007 are estimated to be approximately the same as in 2006.

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 carbon dioxide 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 2006, OG&E obtained refunds of approximately $2.0 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 had one Oklahoma Pollutant Discharge Elimination System (OPDES) permit approved during 2006 and has one other OPDES permit renewal pending. OG&E expects that this permit will be issued during the first or second quarter of 2007. OG&E expects that this permit, when issued, will continue to be reasonable in its requirements, allow operational flexibility and provide reductions in operating costs. Additionally, OG&E filed an application with the state of Oklahoma during 2006 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 quarter of 2007.

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. OG&E 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 OG&E because if OG&E s position is approved, three of the four OG&E 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. On January 25, 2007, a federal court reversed and remanded portions of the 316(b) rules to the EPA. The existing rules remain in effect while the EPA is considering how to respond to the court decision. It is not clear what changes, if any, the EPA will make to the rules or how those changes may affect OG&E.

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 remediate hazardous substances at locations where 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 with respect to future compliance. Enogex may generate 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 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 towards more restrictive 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 and income tax related items. 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. Except as otherwise stated above, in Note 18 below and in Item 3 of this Form 10-K, management, after consultation with legal counsel, does not currently anticipate that liabilities arising out of these pending or threatened lawsuits, claims and contingencies will have a material adverse effect on the Company s consolidated financial position, results of operations or cash flows.

18. 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, 2006, 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 the FERC jurisdictional rates.

Completed Regulatory Matters

2002 Settlement Agreement

On November 22, 2002, the OCC signed a rate order containing the provisions of the 2002 Settlement Agreement. The 2002 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 2002 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 2002 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 were shared with 80 percent to OG&E s Oklahoma customers and 20 percent to OG&E.

OCC Order Confirming Savings

The 2002 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 2002 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 2002 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. OG&E has filed reports with the OCC for the months of January 2004 through December 2006 supporting the savings from the McClain Plant. OG&E expects to file an application with the OCC in the second quarter of 2007 supporting its compliance with the 2002 Settlement Agreement. OG&E expects the OCC to issue an order by the end of 2007 in this matter.

Acquisition of McClain Power Plant

On July 9, 2004, OG&E completed the acquisition of a 77 percent interest in the McClain Plant. This transaction was intended to satisfy the requirement in the 2002 Settlement Agreement to acquire electric generation of not less than 400 MW s.

The closing of the purchase of the McClain Plant was subject to approval from the FERC. The FERC s July 2, 2004 approval was based on an offer of settlement in which OG&E agreed to undertake the following mitigation measures: (i) install certain transmission facilities designed to result in up to 600 MW s 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 s 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 s of ATC available to the Redbud power plant terminated upon completion of the transmission upgrades. On June 20, 2006, the FERC issued an order that OG&E had fully satisfied all of the transmission upgrade requirements associated with the McClain Plant acquisition. Parties in this matter had 30 days to request a rehearing. No request for rehearing was filed with the FERC and OG&E believes the order is final. According to both OG&E s market monitoring plan and the applicable FERC orders, OG&E s market monitoring plan was set to terminate when the SPP installed its own market monitor. Given the implementation of the SPP s external market monitor effective December 1, 2006, OG&E s market monitoring plan effectively ended and OG&E s market monitor was dismissed on December 1, 2006. Also, on December 1, 2006, OG&E

notified the FERC that based on the status of the SPP s internal and external market monitors, the McClain settlement s market monitoring requirements had been fulfilled. On January 16,

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2007, OG&E s market monitor submitted its final report addressing the period from September 30, 2006 to November 30, 2006.

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 (January 1, 2004 through December 31, 2006), 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 subsequent to the end of the 36-month period. At this time, OG&E believes that it achieved at least $75.0 million in savings during this period. OG&E has filed reports with the OCC for the months of January 2004 through December 2006 supporting the savings from the McClain Plant. OG&E expects to file an application with the OCC in the second quarter of 2007 supporting its compliance with the 2002 Settlement Agreement. OG&E expects the OCC to issue an order by the end of 2007 in this matter.

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 pursuant to approved tariffs filed with the OCC. 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. See Note 1 for a discussion of amendments to the tariffs related to Fuel Clause Over Recoveries.

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 that allows customers to pay fuel costs that better reflect operational energy losses related to a specific service level. 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.

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 but does not regulate Enogex s gathering. The OCC regulates gathering 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 system-wide fuel factor for fuel year 2005 (calendar year 2005). The proceedings were resolved by 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. Enogex must file its next rate case no later than October 1, 2007 to comply with the FERC s requirement for triennial filings.

Enogex 2007 Fuel Filing

As required by the fuel tracker provisions of its SOC, Enogex files annually to update its fuel percentages. On November 15, 2006, Enogex filed zonal fuel percentages for the 2007 calendar fuel year. As had been agreed in the settlement of the 2004 Section 311 rate case, Enogex established an East Zone fixed fuel percentage and a West Zone fixed fuel percentage to be recalculated annually to replace the system-wide fixed fuel percentage previously established annually for the Enogex system. By order dated December 19, 2006, the FERC approved and accepted Enogex s November 15, 2006 zonal fuel factors as fair and equitable effective January 1, 2007.

Gas Transportation and Storage Agreement

As part of the 2002 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 2002 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 exceeding the prescribed MDQ s or MHQ s, it pays an overrun service charge. During the years ended December 31, 2006, 2005 and 2004, OG&E paid Enogex approximately $47.5 million, $47.6 million and $49.6 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 $1.0 million to $3.4 million annually. This amount was approximately $1.0 million in 2006 and is projected to be approximately $1.1 million in 2007. The OCC s order required OG&E to refund to its Oklahoma customers the

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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 obligation was fully refunded at September 30, 2006.

In connection with the Enogex gas transportation and storage agreement, OG&E also recorded a refund obligation in Arkansas of approximately $1.1 million at December 31, 2005. OG&E provided to the APSC the OCC evidence and above findings showing that the Arkansas refund was calculated consistently with the Oklahoma refund. OG&E applied the refund obligation to its fuel clause under recoveries balance in April and customers began receiving this refund in April 2006 and will continue through March 2007.

Security Enhancements

On April 8, 2002, OG&E filed a joint application with the OCC Staff requesting approval for security investments and a rider to recover these costs from the ratepayers. 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 stipulation which included a security rider. OG&E implemented the security rider with the first billing period in July 2006 and began charging OG&E s Oklahoma customers approximately $2.4 million annually. In compliance with the OCC order, in October 2006, OG&E filed a report regarding the recovery of the security costs through the authorized recovery rider for the period from July 1, 2006 to September 30, 2006. The OCC authorized tariff provides that the security rider may be updated quarterly. In December 2006, OG&E updated the security rider to recover approximately $2.9 million annually beginning with the first billing cycle in January 2007. OG&E also filed an application with the OCC on December 15, 2006 to amend its security plan to seek approval of approximately $7.6 million of cost increases related to the expanded scope of previously authorized projects and approximately $10.9 million for new security projects. The annual revenue requirement associated with the $18.5 million of capital expenditures is approximately $2.7 million. A procedural schedule was issued in February 2007 in this matter with hearings scheduled to begin on May 30, 2007. OG&E expects the OCC to issue an order in the third quarter of 2007 in this matter.

Competitive Bidding, Prudence Reviews and Other Rules 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. 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 and other matters. Rules were adopted by the OCC on January 18, 2006 and became effective on April 3, 2006. The new rules: (i) establish a competitive procurement process for purchase of long-term electric generation and long-term fuel supplies; (ii) clarify existing law by requiring that a prudence review of utility fuel and generation procurement be conducted no less frequently than every two years; (iii) require a utility to submit an integrated resource plan to the OCC every three years; and (iv) establish a process in accordance with House Bill 1910 whereby a utility may seek pre-approval for recovery of costs associated with transmission upgrades, generation facility modifications caused by environmental requirements and the purchase or construction of generation facilities. OG&E does not expect these rules to have a significant impact on its operations.

OG&E SO2 Allowance Filing

On February 10, 2006, OG&E, the OCC Staff and AES Shady Point (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 for any sales after December 31, 2005. In the application, the parties proposed 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 be shared 80 percent with OG&E s Oklahoma customers and the remaining 20 percent to OG&E. A credit rider was 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. On June 5, 2006, the parties signed a settlement agreement providing that the proceeds of such sales after December 31, 2005 are to be shared 90 percent with OG&E s Oklahoma customers and the remaining 10 percent to OG&E. On June 26, 2006, the OCC approved the settlement agreement, including the 90/10 sharing mechanism. During 2006, OG&E recorded approximately $0.8 million in SO2 sales proceeds from sales in 2006 that are included as an increase in Operating Revenues in the Consolidated Statement of Income.

Review of OG&E s Fuel Adjustment Clause for Calendar Years 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 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. Oklahoma Industrial Energy Consumers, AES, Redbud and PowerSmith Cogeneration Project, L.P intervened in this proceeding. On September 21, 2006, OG&E reached a settlement with the other parties in this case that required no refunds. On October 16, 2006, the OCC issued an order that approved the settlement concluding that OG&E s 2003 fuel costs were prudent and OG&E s 2004 fuel costs were appropriately calculated. Also, as part of the settlement, OG&E agreed to develop minimum filing requirements for future fuel adjustment clause reviews.

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 reduces cogeneration 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 has been updated and approved by the OCC in December of each year through December 2006 and any over/under recovery of the cogeneration credit rider in the current year and prior periods has been automatically included in the next year s rider. OG&E s current cogeneration credit rider expired December 31, 2006. The 2007 cogeneration credit rider is approximately $80.7 million and the total under recovery through 2006 was approximately $3.1 million. OG&E expects to file an application with the OCC in late 2007 to request a cogeneration credit for years after 2007.

Pending Regulatory Matters

OG&E Wind Power Filing

In January 2007, the Centennial wind farm in northwestern Oklahoma was fully in service. Through December 31, 2006, OG&E has spent approximately $171.1 million related to the Centennial wind farm. The OCC previously had approved a settlement agreement approving the Centennial wind power contract and a recovery rider for up to $205 million in construction costs and allowance for funds used during construction. The settlement also indicated that OG&E shall file for a general rate review during 2009 that will permit the OCC to issue an order no later than December 31, 2009 placing the Centennial wind farm in OG&E s rate base. On January 17, 2007, OG&E sent notice to the OCC to trigger the Centennial wind farm rider for the first billing cycle in February 2007. The recovery rider is designed to recover approximately $22.6 million in the first year of operations, which amount will decline over the life of the facility. Because the wind farm rider was implemented in February 2007, OG&E expects to recover approximately $20.7 million under the rider during the remaining 11 months of 2007. OG&E expects the recovery rider to remain in effect through late 2009. As explained below, the recent rate order from the APSC allows for the recovery of the portion of the Centennial wind farm allocable to OG&E s customers in Arkansas.

OG&E Arkansas Rate Case Filing

On July 28, 2006, OG&E filed with the APSC an application for an annual rate increase of approximately $13.5 million to recover, among other things, its investment in, and the operating expenses of, the McClain Plant, the Centennial wind power project and the costs of electric system expansion and upgrades based on a return on equity of 11.75 percent. On November 29, 2006, OG&E reached a settlement with the other parties in this case for an annual rate increase of approximately $5.4 million. In the settlement agreement, the parties also agreed that OG&E would be allowed to recover the full Arkansas portion of the Centennial wind farm. On January 5, 2007, the APSC approved the settlement and issued a rate order that provides for a $5.4 million annual increase in OG&E s electric rates and a 10.0 percent return on equity. The new Arkansas rates became effective in February 2007.

Proposed Construction of Power Plant

On July 18, 2006, the Company announced plans for OG&E to partner with American Electric Power s subsidiary, Public Service Company of Oklahoma (PSO), and the OMPA to build a new 950 MW coal unit at OG&E s existing Sooner plant location near Red Rock, Oklahoma. The estimated $1.8 billion project is the result of PSO s December 2005

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request for proposals in which it sought bids for up to 600 MW s of new base load generation to be available to PSO. The unit, to be called Red Rock, is expected to be one of the cleanest of its size using coal from the Powder River Basin, which is located near Gillette, Wyoming. OG&E will operate the facility and expects to spend approximately $759 million in construction costs related to its 42 percent ownership percentage in the project and approximately $30 million in transmission costs for the project. PSO will own 50 percent and the OMPA will own eight percent. On December 1, 2006, OG&E submitted an application to the ODEQ for an air permit for the Red Rock plant. OG&E is seeking to have the air permit approved by the ODEQ by August 1, 2007. OG&E expects construction to begin in 2007 and is targeting the completion of the power plant in the 2011/2012 timeframe. OG&E filed an application with the OCC on January 17, 2007 asking the OCC to find that its portion of the construction costs are prudent and that a recovery mechanism should be established to recover OG&E s overall cost of capital on the investment during the construction period. The OCC rules provide that the OCC has up to 240 days to issue an order determining OG&E s pre-approval request, however OG&E s application requested that the OCC issue an order by July 20, 2007. The project is contingent upon numerous factors, including the successful completion of contract negotiations and the necessary regulatory and environmental approvals. Under the construction, ownership and operating agreement between OG&E, PSO and the OMPA, the parties could incur up to $60 million (of which approximately $25 million would be borne by OG&E) prior to the receipt of acceptable regulatory approvals and permits. If such approvals and permits were not obtained and the Red Rock project was abandoned, the Company can provide no assurance that these expenditures incurred by OG&E would be recoverable in future rates.

FERC Audit

On May 29, 2006, the FERC notified OG&E that it was commencing an audit to determine whether and how OG&E is complying with: (i) its Open Access Transmission Tariff; (ii) requirements of its market-based rate authorization; (iii) Standards of Conduct and Open Access Same-Time Information System; and (iv) wholesale fuel adjustment clause tariff and other requirements contained in the FERC regulations. Over the past several years, the FERC has conducted numerous audits of utilities across the country to ensure regulatory compliance. OG&E is currently in the process of providing information to the FERC. OG&E cannot predict either the final outcome or the timing of the completion of this audit.

Uniform Fuel Adjustment Clause Filing

On January 23, 2006, the Director of the Public Utility Division of the OCC filed Cause No. PUD 200600012 regarding an application to review the OCC s regulation of the automatic rate adjustment clauses of all public energy utilities operating in Oklahoma and subject to the OCC s jurisdiction. A technical conference for electric utilities was held on March 17, 2006. At this time, OG&E does not believe the outcome of this proceeding will significantly impact the Company.

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 energy imbalance service market that 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 SPP may order certain dispatching of generating units and has implemented a market monitoring plan that 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. On March 20, 2006, the FERC issued an order that conditionally accepted a portion of the filing and suspended and rejected other portions of the filing. After several delays, the SPP Board of Directors voted to implement the energy imbalance service market no earlier than February 1, 2007. The SPP filed a certification of readiness to the FERC on January 18, 2007 that addressed issues raised by intervenors to the proceeding. The SPP energy imbalance service market began operations on February 1, 2007. As one condition to participation in the energy imbalance service market, OG&E, as well as other balancing authorities in the SPP, were required to submit open access tariff schedules setting forth the rates, terms and conditions for the provision of emergency energy service. OG&E submitted the required schedule on September 13, 2006, in Docket No. ER06-1488-000. On January 31, 2007, the FERC issued an order conditionally accepting OG&E s proposed emergency energy schedule, subject to OG&E submitting, within 30 days, a compliance filing making certain revisions required by the FERC.

On August 8, 2005, the SPP filed with the FERC for approval, Docket No. ER05-1285, tariff provisions 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 the Arkansas code, which require 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 consolidated these two dockets, among others, and a public hearing was held on April 4, 2006. On August 10, 2006, the APSC issued an order granting OG&E, subject to certain conditions, permission to transfer functional control of its transmission facilities to the SPP. Also, in a separate order, the APSC granted the application of the SPP for a certificate of public convenience and necessity to transact business as a public utility in Arkansas due to asserting functional control of certain transmission facilities in Arkansas. The APSC, however, denied the SPP s request for a waiver of the applicability of various provisions of state law. Also, on December 1, 2006, the APSC issued an order closing the combined dockets described above.

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 May 13, 2004, the FERC directed all utilities with pending three year market-based reviews to revise the generation market power portion of their three year review to address the new interim tests. OG&E and OERI submitted a compliance filing to the FERC on February 7, 2005 that applied the interim tests to OG&E and OERI. In the compliance filing, OG&E and OERI passed the pivotal supplier screen but did not pass the market share screen in the OG&E control area. OG&E and OERI provided an explanation as to why their failure of the market share screen in the OG&E control area should not be viewed as an indication that they can exercise generation market power.

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 established hearing procedures to investigate whether OG&E and OERI may continue to sell power at market-based rates in OG&E s control area. The order established a rebuttable presumption that OG&E and OERI have the ability to exercise market power in the OG&E control area. OG&E and OERI were 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 to loads that sink 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 sink in OG&E s control area. OG&E and OERI also informed the FERC that any new agreements for long-term sales (one year or longer in duration) to loads that sink in OG&E s control area will be filed with the FERC and that OG&E and OERI will not make such sales under their respective market based rate tariffs. 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 the rates for such sales are not just and reasonable. The refund effective date was March 27, 2006.

On March 21, 2006, the FERC issued an order conditionally accepting OG&E s and OERI s proposal to mitigate the presumption of market power in the OG&E control area. First, the FERC accepted the additional information related to first-tier markets submitted by OG&E and OERI, and concluded that OG&E and OERI satisfy the FERC s generation market power standard for directly interconnected first-tier control areas. Second, the FERC directed the Company to make certain revisions to its mitigation proposal and file a cost-based rate tariff for short-term sales (one week or less) made within the OG&E control area. The FERC also expanded the scope of the proposed mitigation to all sales made within the OG&E control area (instead of only to sales sinking to load within the OG&E control area). On April 20, 2006, the Company submitted: (i) a compliance filing containing the specified revisions to the Company s market-based rate tariffs and the new cost-based rate tariff; and (ii) a request for rehearing asking the FERC to reconsider its expanded mitigation directive contained in the March 21, 2006 order. On May 22, 2006, the FERC issued a tolling order that effectively provided the FERC additional time to consider the April 20, 2006 rehearing request. On July 25, 2006 and August 25, 2006, pursuant to a FERC March 20, 2006 order, OG&E and OERI filed revisions to their market-based rate tariffs to allow them to sell energy imbalance service into the wholesale markets administered by the SPP at market-based rates. The FERC has not yet acted on OG&E s April 20, 2006, July 25, 2006 or August 25, 2006 filings. On February 6, 2007, OG&E and OERI submitted to the FERC a change in status report notifying the FERC that OG&E has placed into service OG&E s Centennial wind farm, a wind farm with a nameplate capacity rating of 120 MW. OG&E and OERI explained that adding this capacity was not material to the FERC s grant of market-based rate status to OG&E and OERI. The FERC has not yet acted on this change in status 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 late 2006, the FERC issued final regulations, pursuant to the 2005 Energy Policy Act, governing the elimination of mandatory purchase obligations by utilities from qualified facilities under PURPA. Those regulations offer the potential for OG&E as a member of the SPP to avoid new mandatory purchase obligations under certain conditions. In addition, in December 2006, Congress enacted and the President signed into law legislation extending through 2008 several energy tax credits, including the tax credit for renewable energy sources such as wind power, that otherwise would have expired in 2007. Looking ahead to 2007, Congress will likely consider several issues of interest to OG&E, including proposals to create a federal mandate for utilities to generate a specified percentage of their power from renewable sources, as well as proposals to impose mandatory global climate emission controls that might limit emissions of carbon dioxide and other so-called greenhouse gases from coal based electric generation facilities.

State Legislative Initiatives

Oklahoma

The 2006 legislative session concluded on May 26, 2006, with no legislation being passed that had a material impact on the Company. One bill, House Bill 1386 was introduced in the 2005 session and was carried over into the 2006 session. That bill, if passed, could have an impact on the

Company s ability to compete with other utility providers. The bill 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. OG&E believes current case law authorizes utilities to serve and expand in an area described above. House Bill 1386 would codify OG&E s belief. The bill failed to be heard in the Senate in 2006.

As discussed above, legislation was enacted in Oklahoma in the 1990 s that was to restructure the electric utility industry in that state. The implementation of the Oklahoma restructuring legislation was delayed and seems unlikely to proceed anytime in the near future. Yet, if ultimately enacted, 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

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previously-enacted Oklahoma 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.

19. 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:

December 31 *(In millions)*	**2006 Carrying Amount**	**Fair Value**	2005 Carrying Amount	Fair Value
Price Risk Management Assets				
Energy Trading Contracts	**$ 42.7**	**$ 42.7**	$ 125.4	$ 125.4
Interest Rate Swaps	**0.9**	**0.9**	0.1	0.1
Price Risk Management Liabilities				
Energy Trading Contracts	**$ 10.3**	**$ 10.3**	$ 120.1	$ 120.1
Interest Rate Swaps	**---**	**---**	0.1	0.1
Long-Term Debt				
Senior Notes	**$ 807.2**	**$ 820.7**	$ 587.8	$ 612.2
Industrial Authority Bonds	**135.4**	**135.4**	135.4	135.4
Enogex Notes continuing operations	**406.7**	**433.5**	407.6	441.2
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. See Note 7 for a discussion of Enogex s trading contracts with set off provisions.

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, 2006 and 2005, 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, 2006. 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, 2006 and 2005, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2006, 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, 2006, 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 14, 2007 expressed an unqualified opinion thereon.

As discussed in Notes 2, 3 and 15 to the consolidated financial statements, in 2006 the Company adopted Statement of Financial Accounting Standards No. 123 (Revised), Share-Based Payment, and Statement of Financial Accounting Standards No. 158, Employers Accounting for Defined Benefit Pension and Other Postretirement Plans.

/s/ Ernst & Young LLP
Ernst & Young LLP

Oklahoma City, Oklahoma

February 14, 2007

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)*		Mar 31	Jun 30	Sep 30	Dec 31	Total
Operating revenues (A)(B)	**2006**	**$ 1,109.8**	**$ 934.3**	**$ 1,130.6**	**$ 830.9**	**$ 4,005.6**
	2005	1,265.3	1,330.2	1,674.1	1,641.9	5,911.5
Operating income (A)(B)	**2006**	**$ 51.8**	**$ 117.7**	**$ 220.6**	**$ 42.6**	**$ 432.7**
	2005	18.7	75.8	188.9	39.0	322.4
Net income (B)	**2006**	**$ 24.9**	**$ 93.7**	**$ 121.4**	**$ 22.1**	**$ 262.1**
	2005	5.3	38.5	111.1	56.1	211.0
Basic earnings per average common share (B)	**2006**	**$ 0.27**	**$ 1.03**	**$ 1.33**	**$ 0.25**	**$ 2.88**
	2005	0.06	0.43	1.23	0.62	2.34
Diluted earnings per average common share (B)	**2006**	**$ 0.27**	**$ 1.02**	**$ 1.31**	**$ 0.24**	**$ 2.84**
	2005	0.06	0.42	1.22	0.62	2.32

(A) These amounts have been restated due to the sales of EAPC and Enerven being reported as discontinued operations during 2005 and the sale of certain gas gathering assets in Kinta, Oklahoma, being reported as discontinued operations during 2006.

(B) As described above in Note 18 of the Notes to Consolidated Financial Statements, the OCC, in its order dated December 12, 2005, granted OG&E a $42.3 million annual increase in the rates charged by OG&E to its retail customers in Oklahoma. These increased rates became effective in January 2006 pursuant to approved tariffs filed with the OCC. In January 2007, OG&E determined that the approved tariffs had inadvertently authorized OG&E to collect, and OG&E had collected, approximately $26.7 million of additional fuel-related revenues during 2006 that was not intended by the December 12, 2005 order. As a result, OG&E filed with the OCC in January 2007 amendments to its previously-authorized tariffs, in order to cease recovery of the fuel-related revenues not intended by the December 12, 2005 order. The $26.7 million, plus $1.2 million of interest, was recorded as a liability under Fuel Clause Over Recoveries on the Consolidated Balance Sheet in the fourth quarter of 2006, and such amounts, along with other Fuel Clause Over Recoveries, will be credited to OG&E s Oklahoma customers in 2007 and 2008 through OG&E s automatic fuel adjustment clause. In addition, OG&E recorded a reduction in operating revenues of approximately $26.7 million and an increase in interest expense of approximately $0.5 million, which resulted in an after tax reduction in net income of approximately $16.7 million in the fourth quarter of 2006. On a quarterly basis, collections of such additional amounts under the previously-authorized tariffs represented approximately $7.8 million of operating revenues ($4.8 million of net income) for the quarter ended March 31, 2006, approximately $7.7 million of operating revenues ($4.7 million of net income) for the quarter ended June 30, 2006 and approximately $5.9 million of operating revenues ($3.6 million of net income) for the quarter ended September 30, 2006.

Dividends

COMMON STOCK

Common quarterly dividends paid (as declared) in 2006 were $0.33 ¼ each for the first three quarters of 2006 and was $0.34 for the fourth quarter of 2006. Common quarterly dividends paid (as declared) in 2005 and 2004 were $0.33 ¼.

Present rate $0.34

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

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 (SEC) rules and forms. In addition, the disclosure controls and procedures ensure that information required to be disclosed is accumulated and communicated to management, including the chief executive officer (CEO) and chief financial officer (CFO), allowing timely decisions regarding required disclosure. As of the end of the period covered by this report, based on an evaluation carried out under the supervision and with the participation of the Company s management, including the CEO and CFO, of the effectiveness of the Company s disclosure controls and procedures (as such term is defined in Rules 13a-15(e) and 15(d)-15(e) under the Securities Exchange Act of 1934), the 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 2006 Form 10-K. The Company has also filed the 2006 Section 303A.12(a) CEO certification with the New York Stock Exchange on June 9, 2006.

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, 2006. 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, 2006, 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
and Chief Executive Officer

/s/ Peter B. Delaney
Peter B. Delaney, 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

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, 2006, 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, 2006, 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, 2006, 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, 2006 and 2005, 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, 2006 of OGE Energy Corp. and our report dated February 14, 2007 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP
Ernst & Young LLP

Oklahoma City, Oklahoma

February 14, 2007

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P.O. Box 321

Oklahoma City, Oklahoma

73101-0321

(405) 553-3000

PLEASE DATE AND SIGN EXACTLY AS NAME APPEARS BELOW. EACH JOINT OWNER SHOULD SIGN. ATTORNEY, EXECUTOR, ADMINISTRATOR,

TRUSTEE OR OTHERS SIGNING IN A REPRESENTATIVE CAPACITY SHOULD GIVE THEIR FULL TITLES.

Please mark your votes as indicated in this example **X**

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.

1. Election of Directors

FOR all NOMINEES (list exceptions below)

WITHHOLD AUTHORITY to vote for all nominees

2. Ratify the appointment of Ernst & Young LLP as our principal independent accountants.

FOR AGAINSTABSTAIN

NOMINEES:

01 Luke R. Corbett

02 Peter B. Delaney

03 Robert Kelley

04 J.D. Williams

3. In their discretion, the proxies are authorized to vote upon such other business as may properly come before the meeting.

Instructions: To withhold authority to vote for any individual nominee, write that nominee s name on the line above.

Discontinue mailing of duplicate Annual Report

I will attend the Annual Meeting.

X / / 2007
Signature of Sharewoner Date

X / / 2007
Signature of Sharewoner Date

FOLD AND DETACH HERE

WE ENCOURAGE YOU TO TAKE ADVANTAGE OF INTERNET OR TELEPHONE VOTING,

BOTH ARE AVAILABLE 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	**OR**	1-866-540-5760	**OR**	Mark, sign and date your proxy card and the return it in the
Use the internet to vote your proxy. Have your proxy card in hand when you access the web site.		Use any touch-tone telephone to vote your proxy. Have your proxy card in hand when you call.		enclosed postage-paid envelope.

If you vote your proxy by Internet or by telephone, you do NOT need to mail back your proxy card.

To vote by mail, mark, sign and date your proxy card and return it in the enclosed postage-paid envelope.

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**® at www.melloninvestor.com/isd where step-by-step instructions will prompt you through enrollment.

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 17, 2007

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 20, 2007, at the Company s Annual Meeting of Shareowners to be held on May 17, 2007, 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, THIS 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.

(Continued on reverse side)

FOLD AND DETACH HERE

321 North Harvey Avenue

Oklahoma City, Oklahoma 73102 RETAIN FOR ADMITTANCE

Annual Meeting of

OGE Energy Corp. Shareowners

Thursday, May 17, 2007 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 1-44

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.