OGE ENERGY CORP
Form DEF 14A
March 30, 2004

OGE Energy Corp. PO Box 321
Oklahoma City, Oklahoma 73101-0321
405-553-3000
www.oge.com

OG&E

March 30, 2004

Securities and Exchange Commission
Division of Corporation Finance
450 Fifth Street, N.W.
Washington, D.C. 20549

Gentlemen:

On behalf of OGE Energy Corp., enclosed for electronic filing, pursuant to Rule 14a-6(b), is a definitive copy of the proxy solicitation material relating to the Annual Meeting of Shareowners of the Company to be held on May 20, 2004.

Please note that copies of the proxy solicitation material are this day being sent to the New York and Pacific Stock Exchanges in accordance with Rule 14a-6(b).

The Company intends to commence mailing the foregoing material to its shareowners on approximately March 30, 2004, and to complete the same as soon as possible.

Sincerely,

Carla D. Brockman
Corporate Secretary

Enclosure

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

[ ] Fee Computed on table below per Exchange Act Rules 14a-6(i)(4) and 0-11.

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):

4) Proposed maximum aggregate value of transaction:

5) Total fee paid:

[ ] Fee paid previously with preliminary materials.

[ ] Check box if any part of the fee is offset as provided by exchange Act Rule 0-11(a)(2) and identify the filing for which the offsetting fee was paid previously. Identify the previous filing by registration statement number, or the Form or Schedule and the date of its filing.

1) Amount Previously Paid:

2) Form, Schedule or Registration Statement No.:

3) Filing Party:

4) Date Filed:

OGE Energy Corp.

Proxy Statement
and
Notice of Annual Meeting

May 20, 2004

OG+E

Contents

Notice of Annual Meeting
of Shareowners
and Proxy Statement

Thursday, May 20, 2004, at 10:00 a.m.

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

OGE Energy Corp.

March 30, 2004

Dear Shareowner:

You are cordially invited to attend the annual meeting of OGE Energy Corp. at 10:00 a.m. on Thursday, May 20, 2004, 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,

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

Notice of Annual Meeting of Shareowners

The Annual Meeting of Shareowners of OGE Energy Corp. will be held on Thursday, May 20, 2004, at 10:00 a.m. at the National Cowboy and Western Heritage Museum, 1700 Northeast 63rd Street, Oklahoma City, Oklahoma, for the following purposes:

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

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

The map on page 24 will assist you in locating the National Cowboy and Western Heritage Museum.

Shareowners who owned stock on March 22, 2004, 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.

Carla D. Brockman
Corporate Secretary

Dated: March 30, 2004

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, 2004

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 20, 2004, at 10:00 a.m. For the convenience of those shareowners who may attend the meeting, a map is printed on page 24 that gives directions to the National Cowboy and Western Heritage Museum. At the meeting, it is intended that the first item in the accompanying notice will be presented for action by the owners of the Company s Common Stock. The Board of Directors does not now know of any other matters to be presented at the meeting, but, if any other matters are properly presented to the meeting for action, the persons named in the accompanying proxy will vote upon them in accordance with their best judgment.

Your Board of Directors is sending you this proxy statement in connection with the solicitation of your proxy for use at the Annual Meeting. When you vote by Internet, by telephone or by mail, you appoint Steven E. Moore, Herbert H. Champlin and Martha W. Griffin as your representatives at the Annual Meeting. Mr. Moore, Mr. Champlin and Mrs. Griffin 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 Mrs. Griffin will vote your shares, under your proxy, in accordance with their best judgment.

Voting Procedures; Revocation of Proxy

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

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 Dividend Reinvestment and Stock Purchase Plan(DRIP) 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, 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 22, 2004, you are entitled to one vote per share upon each matter presented at the meeting.

On March 1, 2004, there were 87,546,348 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

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other employees of the Company may solicit proxies by mail, personal interview, telephone and/or telegraph. In addition, we have retained Mellon Investor Services to assist in the solicitation of proxies, at a fee of approximately $8,000 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, 2004. 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, 2004, to all of our shareowners who owned stock on March 22, 2004.

Voting Under Plans

If you are a participant in our DRIP, your proxy will represent the shares held on your behalf under the DRIP 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 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. 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 nonroutine 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 nine members. The directors are classified into three groups. One class of directors is elected at each year s Annual Meeting for a three-year term and to continue in office until their successors are elected and qualified. The following three persons are the nominees of the Board to be elected for such three-year term at the Annual Meeting to be held on May 20, 2004: Mr. Luke R. Corbett, 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.

The enclosed proxy, unless otherwise specified, will be voted in favor of the election as directors of the previously listed three nominees. The Board of Directors does not know of any nominee who will be unable to serve, but if any of them should be unable to serve, the proxy holder may vote for a substitute nominee. No nominee or director owns more than .78% of any class of voting securities of the Company.

For the nominees described herein to be elected as directors, they must receive 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.

Each director of the Company during 2003 was also a director of Oklahoma Gas and Electric Company (OG&E). The Company became the parent company of OG&E pursuant to a corporate reorganization, effective December 31,1996.

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INFORMATION ABOUT DIRECTORS AND NOMINEES

The following contains certain information as of March 1, 2004, concerning the three nominees for directors, as well as the directors whose terms of office extend beyond the Annual Meeting on May 20, 2004.

Nominees For Election For Term Expiring at 2007 Annual Meeting of Shareowners

LUKE R. CORBETT, 57, is Chairman and Chief Executive Officer of Kerr-McGee Corporation, which is engaged in oil and gas exploration and production and chemical operations. He has been employed by Kerr-McGee Corporation for more than 17 years, having served as Chairman and Chief Executive Officer since 1997; President and Chief Operating Officer from 1995 to 1997; and Group Vice President from 1992 to 1995. Mr. Corbett also serves as a member of the Board of Directors of BOK Financial Corporation and Noble Corporation. Mr. Corbett has been a director of the Company since December 31, 1996, and of OG&E since December 1, 1996, and is chairman of the compensation committee and is a member of the audit committee of the Board.

Photo

ROBERT KELLEY, 58, is President of Kellco Investments Inc., a private investment company. Prior to May 1, 2001, he served as Chairman of the Board of Noble Affiliates, Inc., an independent energy company with exploration and production operations in the United States and international operations in China, Equador, Equatorial Guinea and the U.K. sector of the North Sea. Prior to October 2, 2000 he also served as President and Chief Executive Officer of Noble Affiliates, Inc. and of its three subsidiaries: Samedan Oil Corporation, Noble Gas Marketing Inc. and Noble Trading, Inc. Mr. Kelley also serves as a member of the Board of Directors of Lone Star Technologies, Inc. and Cabot Oil and Gas Corporation. Mr. Kelley has been a director of the Company since December 31, 1996, and of OG&E since January 17, 1996, and is chairman of the audit committee and a member of the compensation committee of the Board.

Photo

J. D. WILLIAMS, 66, is founder and a former member of Williams & Jensen, P.C., a law firm in Washington, D. C. having resigned as a member of the firm in 1991. He continues to practice law as an employee of Williams & Jensen, P.C. and is involved in various civic and related matters. During 2003, the Company retained Williams & Jensen to perform various legal services on its behalf and expects to retain Williams & Jensen to provide similar services in 2004. Mr. Williams has been a director of the Company since January 2001, and is chairman of the nominating and corporate governance committee and is a member of the audit committee of the Board.

Photo

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Directors Whose Terms Expire at 2006 Annual Meeting of Shareowners

WILLIAM E. DURRETT, 73, is Senior Chairman of the Board of American Fidelity Corporation, an insurance holding company and Chairman of North American Insurance Agency, Inc. From May 1998 to October 1999, he served as President and Chief Executive Officer of North American Insurance Agency, Inc. From 1978 to 1998, Mr. Durrett served as President and Chief Executive Officer of American Fidelity Corporation. He also served as Chairman of American Fidelity Corporation from 1989 to 1998. He also serves as a member of the

Photo

Boards and holds various executive positions in numerous other subsidiaries of American Fidelity Corporation. He serves as a director of BOK Financial Corporation and of INTEGRIS Health. Mr. Durrett has been a director of the Company since December 31, 1996, and of OG&E since March 1991, and is a member of the audit committee and the nominating and corporate governance committee of the Board.

JOHN D. GROENDYKE, 59, is Chairman of the Board and Chief Executive Officer of Groendyke Transport Incorporated, a bulk truck transportation company in Enid, Oklahoma. Mr. Groendyke has worked at Groendyke Transport, Inc. since 1965. Mr. Groendyke is also Chairman of the Board and President of Bell Transport, Inc.; Oringderrf Tank Line, Inc.; Transport Company, Inc.; and Triple A Transport and is Chairman of the Board of GTI Insurance Co. Inc. and of James, Inc. Mr. Groendyke also serves as Director of Central Service Corp. and Central National Bank. Mr. Groendyke has been a director of the Company since January 2003 and is a member of the nominating and corporate governance committee of the Board.

Photo

STEVEN E. MOORE, 57, is Chairman, President and Chief Executive Officer of the Company and of OG&E, having been appointed to such positions with the Company effective December 31, 1996. Mr. Moore was appointed President of OG&E in August 1995, and as Chief Executive Officer and Chairman of OG&E in May 1996. Mr. Moore has been employed by OG&E for more than 28 years, having previously served as Senior Vice President of Law and Public Affairs. He also serves as a director of BOK Financial Corporation, INTEGRIS Health, and has served on many industry-wide committees in the electric utility industry. Mr. Moore has been a director of the Company since 1996 and of OG&E since October 1995.

Photo

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Directors Whose Terms Expire at 2005 Annual Meeting of Shareowners

HERBERT H. CHAMPLIN, 66, is President of Champlin Exploration, Inc., an independent oil producer, and Chairman of Enid Data Systems, computer marketers, both located in Enid, Oklahoma. Mr. Champlin has been a director of the Company since December 31, 1996, and of OG&E since 1982, and is a member of the audit and compensation committees of the Board. Mr. Champlin also was engaged separately during 2002 as a part of his principal business occupation in the petroleum industry and had interests in oil and gas wells.

Photo

MARTHA W. GRIFFIN, 69, owner of Martha Griffin White Enterprises, is presently engaged in the management of her personal investments, the operation of a ranch, oil and gas properties and various civic activities. Prior to September 30, 1994, she served as Chairman of the Board of Griffin Television, Inc., located in Oklahoma City, Oklahoma, and Chairman of the Board of Griffin Food Company (a subsidiary of Griffin Television, Inc.). Mrs. Griffin has been a director of the Company since December 31, 1996, and of OG&E since 1987, and is a member of the nominating and corporate governance committee and the compensation committee of the Board.

Photo

RONALD H. WHITE, M.D., 67, is a practicing cardiologist and President, Partner and Director of Oklahoma Cardiovascular Associates, and a member of the Board of Managers of Oklahoma Heart Hospital. He was a member of the Board of Regents of the University of Oklahoma for 14 years. Presently Dr. White is a member of the Oklahoma State Regents for Higher Education. Dr. White has been a director of the Company since December 31, 1996, and of OG&E since 1989, and is a member of the compensation committee and the nominating and corporate governance committee of the Board.

Photo

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INFORMATION CONCERNING THE BOARD OF DIRECTORS

Each member of our Board of Directors was also a director of OG&E during 2003. The Board of Directors of the Company met on 6 occasions during 2003 and the Board of Directors of OG&E met on 6 occasions during 2003. Each director attended at least 89% 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 Directors who are members of the various committees of the Company serve in the same capacity for purposes of the OG&E Board.

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

The members of the committees during 2003, and the duties and responsibilities of the committees are described below.

Name of Committee and Members	General Functions of the Committee **	Number of Meetings in 2003
Compensation Committee: Herbert H. Champlin Luke R. Corbett* Martha W. Griffin Robert Kelley Ronald H. White	Oversees o compensation of principal officers o salary policy o benefit programs o compensation for outside directors o future compensation objectives and goals of the Company	3
Audit Committee: Herbert H. Champlin Luke R. Corbett William E. Durrett Robert Kelley* J.D. Williams	Oversees financial reporting process o evaluate performance of independent auditors o select independent auditors o discuss with internal and independent auditors scope and plans for audits, adequacy and effectiveness of accounting and financial controls, and results of their examinations o review interim financial statements and annual financial statements to be included in Form 10-K	7
Nominating and Corporate Governance Committee: William E. Durrett Martha W. Griffin John D. Groendyke Ronald H. White J.D. Williams*	Reviews and recommends o nominees for election as directors o membership of director committees o succession plans o various corporate governance issues o evaluation of incumbent directors	2

* Chairperson
** The specific duties for each committee are set forth in the charter of the committee, which, in the case of the audit committee, is attached as Annex A, and, in the case of the compensation committee and the nominating and corporate governance committee, is available on the OGE Energy web site at *www.oge.com* under the heading Investors, Corporate Governance.

Corporate Governance

Governance Guidelines. The Board of Directors of the Company has long had in place good standards of corporate governance. Recently, the Board of Directors formalized these standards and adopted Guidelines for Corporate Governance that outlined the responsibilities of the Board, as well as qualifications for directors to serve on the Board. Our Code of Conduct, that is applicable to all of our directors, officers and employees, and the Guideline for Corporate Governance were most recently amended in 2003 to ensure compliance with the Sarbanes-Oxley Act of 2002 and the listing standards of the New York Stock Exchange. We also have a separate code of ethics that applies to our chief executive officer and our senior financial officers, including, our chief financial officer and our chief accounting officer, and 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 new legislative and other governance requirements of the New York Stock Exchange. All of our corporate governance material, including our codes of conduct and ethics, our Guidelines for Corporate Governance and all of our committee charters, is available for public viewing on the OGE Energy web site at www.oge.com under the heading Investors, Corporate Governance.

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

- A director who is an employee, or whose immediate family member is 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 receives, or whose immediate family member receives, more than $100,000 per year 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 per year in such compensation;
- A director who is affiliated with or employed by, or whose immediate family member is affiliated with or employed in a professional capacity by, a present or former internal or external auditor of the Company or any of our subsidiaries is not independent until three years after the end of the affiliation or the employment or auditing relationship;
- A director who is employed, or whose immediate family member is employed, as an executive officer of another company where any of our or any of our subsidiaries present executives serve 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 an executive officer or an employee, or whose immediate family member is an 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 single fiscal year, exceeds the greater of $1 million, or 2% of such other company's consolidated gross revenues, is not independent until three years after falling below such threshold; and
- No director qualifies as independent unless the Board affirmatively determines that the director has no other relationship with us or any of our subsidiaries (either directly or as a partner, shareholder or officer of an organization that has a relationship with us or any of our subsidiaries) that in the opinion of the Board of Directors could be considered to affect the directors ability to exercise his or her independent judgement as a director.

The Board determined that each member of the Board, except for Steven E. Moore, meets the aforementioned independence standards. Mr. Moore does not meet the aforementioned independence standards, because he is the current Chief Executive Officer and an employee of the Company.

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

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

Communications with the Board of Directors. Shareowners who wish to communicate with members of the Board, including the independent directors individually or as a group, may send correspondence to them in care of the Corporate Secretary at the Company s principal offices, 321 North Harvey, P.O. Box 321, Oklahoma City, Oklahoma 73101-0321. We currently do not intend

to have the Corporate Secretary screen this correspondence, but we may change this policy if directed by the Board due to the nature and volume of the correspondence.

The Company encourages each of its Board members to attend the Annual Meeting and the directors are expected to attend whenever reasonably possible. All nine of the Board members attended the Annual Meeting in 2003.

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 not 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, 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 nonofficer directors of the Company during 2003 consisted of an annual retainer fee of $64,000, of which $2,000 was payable monthly in cash (the same amount that has been paid monthly since August 1994) and $40,000 was deposited in the director s account under the Directors Deferred Compensation Plan and converted to 1,679.261 common stock units based on the closing price of the Company s Common Stock on December 1, 2003. The chairmen of the audit, compensation and nominating and corporate governance committees received an additional $3,000 annual cash retainer in 2003. In addition, all non-officer directors received $1,000 for each Board meeting and $1,000 for each committee meeting attended. These amounts represent the total fees paid to directors in their capacities as directors of the Company and OG&E.

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

Amounts credited to the accounts are assumed to be invested in one or more of the investment options permitted under the Plan. During 2003, those investment options included a Company Common Stock fund, whose value was determined based on the stock price of the Company s Common Stock, a money market fund, a bond fund and several stock funds.

When an individual ceases to be a director of the Company, all amounts credited under the Plan are paid in cash in a lump sum or installments. As an alternative to these investment options, prior to January 1, 2000, a non-officer director could elect to have all or any deferred portion of the attendance fees and the cash portion of the annual retainer fee applied to purchase life insurance for the director. Any deferred attendance or retainer fees used to purchase life insurance may not be transferred to other investment options.

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

REPORT OF AUDIT COMMITTEE

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

The Audit Committee has five members, none of whom has any relationship to the Company that interferes with the exercise of his or her independence from management and the Company, and each of whom qualifies as independent under the standards used by the New York Stock Exchange, where the Company s shares are listed. The Audit Committee operates under a written charter that has been approved by the Board of Directors. A copy of the Audit Committee charter is attached as Annex A. The Audit Committee annually reviews and reassesses the adequacy of its charter. Among other things, the charter specifies the 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 2003 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 the 2003 financial statements with the Company s independent auditors. 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. 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. 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 in accordance with the requirements of the Independence Standards Board.

The Audit Committee also discussed with the Company s internal and independent auditors the overall scope and plans for their respective audits for 2004. 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 7 meetings during 2003 and the Chairman of the Audit Committee met with the auditors by telephone on a quarterly basis to discuss the Company s quarterly financial statements.

Fees For Independent Auditors

As discussed further under the caption Change of Independent Public Accountants on page 23, on May 16, 2002, the Company, on the advice of the Audit Committee, dismissed Arthur Andersen LLP as its independent public accountants and engaged Ernst & Young LLP as its independent public accountants for fiscal year 2002. During 2002, Arthur Andersen LLP rendered professional services to the Company in connection with, among other things, the review of the unaudited financial statements included in the Company s Quarterly Report of Form 10-Q filed with the Securities and Exchange Commission on May 15, 2002. During 2002, Ernst & Young LLP rendered professional services to the Company in connection with, among other things, the audit of the Company s annual financial statements for the fiscal years ended December 31, 2000, 2001 and 2002 and the reviews of the unaudited financial statements included in the Company s Quarterly Reports of Form 10-Q filed with the SEC on August 14, 2002 and November 14, 2002.

Audit Fees

Total audit fees for 2002 were $1,122,104 for the Company s 2002 financial statement audit. These fees include $635,000 for the audits of the 2000 and 2001 financial statements of the Company and for certain subsidiaries. Total audit fees for 2003 were $789,326, which includes $140,755 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 2003, this amount includes estimated billings for the completion of the 2003 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, 2002 were $52,000 for employee benefit plan audits.

The aggregate fees billed for audit-related services for the fiscal year ended December 31, 2003 were $91,550. These fees include $56,000 for employee benefit audits and $35,550 for other audit-related services.

Tax Fees

The aggregate fees billed for tax services for the fiscal year ended December 31, 2002 were $840,580. These fees include $675,000 for tax assistance with the Oklahoma Investment Tax Credits, $76,800 for the review of federal and state tax returns and $88,780 for other tax services.

The aggregate fees billed for tax services for the fiscal year ended December 31, 2003 were $1,028,594. These fees include $478,206 for a change in our tax accounting method, $338,742 for assistance with the Oklahoma Investment Tax Credits, $53,490 for the review of federal and state tax returns and $158,156 for other tax services.

All Other Fees

There were no other fees billed to the Company in 2002 or 2003 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, 2003, for filing with the Securities and Exchange Commission. The Audit Committee selected Ernst & Young LLP to review the Company s Quarterly Report on Form 10-Q for the quarter ended March 31, 2004 and, at its meeting in May 2004, the Audit Committee will determine whether Ernst & Young LLP will be selected as the Company s independent public accountants for 2004. Representatives of Ernst & Young LLP will be present at the Annual Meeting of Shareowners and will have the opportunity to make a statement if they so desire. Such representatives will be available to respond to appropriate questions from shareowners at the meeting.

Audit Committee Pre-Approval Procedures

Rules adopted by the Securities and Exchange Commission 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 2003, 100% of the audit-related fees, tax fees and all other fees were pre-approved by the Audit Committee or the Chairman of the Audit Committee pursuant to delegated authority.

Audit Committee
Robert Kelley, Chairman
Herbert H. Champlin, member
Luke R. Corbett, member
William E. Durrett, member
J.D. Williams, member

EXECUTIVE OFFICERS COMPENSATION

The Compensation Committee of the Board of Directors of the Company (the Committee) administers our executive compensation program. The Committee s report on compensation paid to executive officers during 2003 is set forth below.

REPORT OF COMPENSATION COMMITTEE ON EXECUTIVE COMPENSATION

General. The primary goals of the Committee in setting executive compensation in 2003 were: (i) to provide a competitive compensation package that would enable us to attract and retain key executives and (ii) to align the interests of our executives with those of our shareowners and also with our performance.

Compensation to our executive officers in 2003 was comprised primarily of salary, annual awards under our Annual Incentive Compensation Plan and long-term awards under our Stock Incentive Plan. In an effort to ensure the continued competitiveness of our executive compensation policies, the Committee in setting base salaries and making annual and long-term incentive awards, considered the compensation paid at the 50th percentile to executives with similar duties within the following three groups: (i) the 2002 Energy Services Industry Executive Compensation Database (the Energy Services Survey Group), consisting of approximately 89 electric services organizations, (ii) the 2002 General Industry Executive Compensation Database (the General Industry Survey Group), consisting of more than 750 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).1 All compensation data from these surveys was size-adjusted so that it would compare to the Company s or a subsidiary s revenues, as appropriate, and was updated using a 3.75 percent update factor to reflect anticipated 2003 compensation levels.

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

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

Base Salary. The base salaries for our executive officers in 2003 were designed to be competitive with the Blended Industry Survey Group and generally approximated the salary at the 50th percentile of the range for executives with similar duties in such survey group. Actual base salaries were determined based on individual performance and experience. The salaries of executive officers for 2003 were determined in October 2002, with an effective date of January 1, 2003. Salaries were subject to adjustment during the year if an individual s duties and responsibilities changed. The 2003 base salary amounts for the most highly compensated executive officers are shown in the salary column of the Summary Compensation Table on page 16 and remain unchanged from their 2002 base salary amounts.

Annual Incentive Compensation Plan. Awards with respect to 2003 performance were made under the Annual Incentive Compensation Plan to 89 employees, including all executive officers. The Plan was designed to provide key management personnel with annual incentive awards, the payment of which is tied to the achievement of specified Company objectives. Payouts of the award were in cash and were dependent entirely on the

1 The companies in the Energy Services Survey Group, General Industry Survey Group and Blended Industry Survey Group are not the same as the companies in the Dow Jones U.S. Electric Utilities Index or the S&P 500 Electric Utilities Index utilized in the Stock Performance Graph on page 21. The survey groups were selected by Towers Perrin, the Company s compensation consultants, and, in the judgment of the Committee, are appropriate peer groups to consider for compensation purposes.

achievement of the corporate goals that were established by the Committee in January 2003.

For Messrs. Moore, Strecker and Delaney, the three most senior executive officers of the Company, the corporate goals were based: (i) 50% on a Company consolidated earnings per share target established by the Committee (the Earnings Target), (ii) 25% on a combined operating and maintenance expense and capital expenditure target for the Company and its subsidiaries (other than Enogex and its subsidiaries) established by the Committee (the O&M/Capital Target), and (iii) 25% on consolidated net income of Enogex and its subsidiaries (the Unregulated Income Target). These three corporate goals were also used in establishing the corporate goals for all other executive officers. However, the weighting of the goals was slightly different with the corporate goals for one executive officer being based 50% on the Earnings Target and 50% on the O&M/Capital Target while for the remaining executive officers the corporate goals were based 50% on the Earnings Target, 35% on the O&M/Capital Target and 15% on the Unregulated Income Target.

The amount of the award for each executive officer was expressed as a percentage of base salary (the targeted amount), with the officer having the ability, depending upon achievement of the corporate goals, to receive from 0% to 150% of such targeted amount. For 2003, the targeted amount ranged from 25% to 75% of base salary and approximated the 50th percentile of the level of such awards granted to comparable executives in the Blended Industry Survey Group.

The percentage of the targeted amount that an officer ultimately received based on corporate performance was subject to being decreased, but not increased, at the discretion of the Committee. For 2003, corporate performance of the Earnings Target, the O&M/ Capital Target and the Unregulated Income Target exceeded the minimum levels of achievement established by the Committee and resulted in total payouts under the Annual Incentive Plan to executive officers ranging from 35.8% to 108.8% of their base salaries and from approximately 135% to 145% of their targeted amounts. Payouts under the Annual Incentive Plan are reflected in the bonus column of the Summary Compensation Table on page 16.

Long-Term Awards. Another significant component of executive compensation in 2003 was long-term awards under our Company s Stock Incentive Plan, which also was approved by the shareowners at the 1998 Annual Meeting. The Plan provides for the grant of any or all of the following types of awards: stock options, stock appreciation rights, restricted stock and performance units. In 2003, the Committee made awards of stock options and performance units. In making awards of stock options, the Committee considered numerous factors as discussed below and reviewed the expected value of long-term compensation payable to executives in the 50th percentile of the Energy Services Survey Group and the 50th percentile of the Blended Industry Survey Group. The expected value of long-term compensation payable to the most senior level executives in the 50th percentile of the Blended Industry Survey Group was substantially higher than the expected value of long-term compensation payable to comparable executives in the 50th percentile of the Energy Services Survey Group and substantially higher than the expected value of long-term compensation awarded by the Committee in the past to comparable executive officers at the Company. While the Committee intends to continue to consider the long-term compensation payable to comparable executives in the 50th percentile of the Blended Industry Survey Group in awarding long-term compensation to the Company s executive officers, the Committee s intent generally in 2003 was to provide executive officers with an aggregate value of long-term compensation equal to the expected value of long-term incentives payable to comparable executives in the 50th percentile of the Energy Services Survey Group.

Historically, the Committee had awarded long-term compensation in the forms of stock options and restricted stock. At its meeting in the fourth quarter of 2002, the Committee chose to discontinue awarding restricted stock and, instead, to make awards of stock options and performance units commencing in 2003, with 50% of an executive officer s award being in the form of stock options and 50% in the form of performance units.

The stock options were granted to executive officers during the first quarter of 2003 at an exercise price equal to the fair market value at the date of the grant. The options have a 10 year term and vest over 3 years, with one-third of the options becoming exercisable at the end of each year. Since options were granted with an exercise price equal to the market value of our Common Stock at the time of grant, they provide no value unless our stock price increases after the options are granted. These awards are thus tied to stock price appreciation in excess of the stock s value at time of grant, rewarding executives as if they shared in the ownership of the Company. The number of shares subject to options for each executive officer was determined by taking the expected value to be provided in options, as determined above, and dividing that amount by the estimated current value of an option for our stock using a variation of the Black-Scholes Option Pricing methodology provided by an outside compensation consultant. This resulted in executive officers receiving stock options with an estimated value of approximately 12.5% to 72.5% of their 2003 base salaries.

The performance units also were granted to executive officers during the first quarter of 2003. The number of performance units granted was determined by taking the amount of the executive s long-term award to be delivered in performance units (adjusted on a present value basis), as determined above, and dividing that amount by a recent closing price for the Company s Common Stock. This resulted in executives receiving performance units with an expected value at the date of grant of from 12.5% to 72.5% of their 2003 base salaries. The value of the performance units is substantially dependent upon the changing value of the Company s Common Stock in the marketplace. Each executive officer is entitled to receive from 0% to 200% of the performance units contingently awarded to the executive based on the Company s total shareholder return over a three-year period (defined as share price increase plus dividends paid, divided by share price at beginning of the period) measured against the total shareholder return for such period (TSR) by a peer group selected by the Committee. The peer group for measuring the Company s TSR performance consists of approximately 88 utility holding companies and gas and electric utilities in the Standard & Poor s Utility Index.

CEO Compensation. The 2003 compensation for Mr. Moore consisted of the same components as the compensation for other executive officers. Mr. Moore s 2003 salary remained unchanged from the 2002 amount of $710,000, and his 2003 targeted award under the Annual Incentive Plan remained at 75% of this base salary, which the Compensation Committee believed were appropriate levels based on his performance and his prior experience. As a result of 2003 corporate performance described above, he received a payout of $772,817 under the Annual Incentive Plan, representing approximately 108.8% of his base salary and 145% of his targeted award. The award of stock options and performance units 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 Company Survey Group. Consideration also was given 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. Based on these factors, the Committee determined to grant Mr. Moore stock options and performance units having an expected value of approximately 145% of his 2003 base salary.

Other Benefits. Virtually all of our employees, including executive officers, are eligible to participate in the Retirement Savings Plan and pension plan. Both the Retirement Savings Plan and pension plan have supplemental restoration plans that enable executive officers to receive the same benefits that they would have received in the absence of limitations imposed by the federal tax laws on contributions or payouts. In addition, a Supplemental Executive Retirement Plan (the SERP), which was adopted in 1993, offers attractive pension benefits to lateral hires. No officer, other than Mr. Delaney, participated in the SERP during 2003. The SERP is not expected to benefit other existing executive officers generally who remain employed by the Company or OG&E until age 65. In reviewing the benefits under the SERP, Retirement Savings Plan, pension plan and related restoration plans, the Committee sought in 2003 to provide participants with benefits at least commensurate with those offered by other utilities of comparable size. The restoration plans for the Retirement Savings Plan and pension plan contain provisions requiring their immediate funding in the event of certain mergers, consolidations or tender offers involving the Company.

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

Compensation Committee
Luke R. Corbett, Chairman
Herbert H. Champlin, member
Martha W. Griffin, member
Robert Kelley, member
Ronald H. White, member

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SUMMARY COMPENSATION TABLE

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

					Long-Term Compensation			
		Annual Compensation			Awards		Payouts	
Name and Principal Position	Year	Salary ($)	Bonus(1) ($)	Other Annual Compensation ($)	Restricted Stock Awards(2) ($)	Securities Underlying Options/ SAR (#)	LTIP Payouts ($)	All Other Compensation(3) ($)
S.E. Moore, Chairman,	2003	710,000	772,817	0	0	202,300	0	48,558
President and	2002	710,000	149,885	0	0	218,500	0	35,361
Chief Executive Officer	2001	650,000	0	0	297,478	104,700	0	55,215
A.M. Strecker	2003	460,000	433,939	0	0	90,400	0	37,174
Executive Vice President and	2002	460,000	84,161	0	0	97,600	0	26,186
Chief Operating Officer	2001	420,000	0	0	132,918	43,300	0	34,112

P.B. Delaney (4)	2003	400,000	348,312	0	0	98,200	0	16,705
E.V.P. Finance and Strategic Planning and CEO - Enogex Inc.	2002	300,000	24,192	0	0	84,900	0	156,577
J.R. Hatfield	2003	310,000	221,932	0	0	51,800	0	28,151
Sr. Vice President and	2002	310,000	52,205	0	0	55,900	0	16,921
Chief Financial Officer	2001	275,000	7,035	0	76,141	21,300	0	21,560
J.T. Coffman	2003	255,000	143,065	0	0	30,100	0	26,701
Sr. Vice President	2002	255,000	8,883	0	0	32,500	0	20,036
Power Supply	2001	235,000	4,379	0	44,198	18,200	0	22,580

(1) As explained on page 14, amounts in this column reflect payouts under the Annual Incentive Compensation Plan.

(2) Amounts in this column reflect the market value of the shares of Restricted Stock awarded under the existing Stock Incentive Plan, based on the closing price of the Company's Common Stock on the date the award was made. No shares of Restricted Stock were awarded in 2002 or 2003. The number of shares awarded in 2001, was as follows: (i) Mr. Moore, 12,889 shares; (ii) Mr. Strecker, 5,759 shares; (iii) Mr. Hatfield, 3,299 shares; and (iv) Mr. Coffman, 1,915 shares. In the absence of death, disability or normal retirement, the shares awarded to these individuals are subject to forfeiture for three years with the amount the recipient ultimately receives dependent on Company performance. The total number of shares and market value of Restricted Stock held by each of the named individuals as of December 31, 2003, were as follows: Mr. Moore, 12,889 shares, $311,785; Mr. Strecker, 5,759 shares, $139,310; Mr. Delaney, 0 shares, $0; Mr. Hatfield, 3,299 shares, $79,803; and Mr. Coffman, 1,915 shares, $46,325. Dividends are paid to these individuals on the shares of Restricted Stock owned by them.

(3) Amounts in this column for 2003 reflect: (i) for Mr. Moore, $38,695 (Retirement Savings Plan and Deferred Compensation Plan) and $9,863 (insurance premiums); (ii) for Mr. Strecker, $24,487 (Retirement Savings Plan and Deferred Compensation Plan) and $12,687 (insurance premiums); (iii) Mr. Delaney, $12,000 (Retirement Savings Plan and Deferred Compensation Plan) and $4,705 (insurance premiums); (iv) for Mr. Hatfield, $10,866 (Retirement Savings Plan and Deferred Compensation Plan) and $17,285 (insurance premiums); and (v) for Mr. Coffman, $11,875 (Retirement Savings Plan and Deferred Compensation Plan) and $14,826 (insurance premiums). A significant portion of the insurance premiums reported for each of these individuals is for life insurance policies and such premiums are recovered by the Company from the proceeds of the policies.

(4) Mr. Delaney joined the Company effective April 1, 2002.

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OPTIONS AND STOCK APPRECIATION RIGHTS (SARs)

The following table indicates for each of the named executives (i) the extent to which the Company used stock options and SARs for executive compensation purposes in 2003 and (ii) the potential value of such options and SARs as determined pursuant to the SEC rules.

Options and SARs Granted in 2003

	Individual Grants				Potential Realizable Value at Assumed Annual Rates of Stock Price Appreciation for Option Term	
(a)	(b)	(c)	(d)	(e)	(f)	(g)
Name	Options/SARs Granted #(1)	% of Total Options and SARs Granted to Employees in 2003	Exercise or Base Price ($/Share)	Expiration Date	5%($)(2)	10%($)(2)
S.E. Moore	202,300	24.12	$16.685	1/27/13	$2,122,756	$5,379,479
A.M. Strecker	90,400	10.78	16.685	1/27/13	948,577	2,403,880

P.B. Delaney	98,200	11.71	16,685	1/27/13	1,030,423	2,611,294
J.R. Hatfield	51,800	6.18	16,685	1/27/13	543,543	1,377,445
J.T. Coffman	30,100	3.59	16,685	1/27/13	315,843	800,407

(1) Options were granted on January 27, 2003 and become exercisable in one-third annual installments beginning one year from the date of grant. No SARs were awarded for 2003.

(2) The hypothetical potential appreciation shown in columns (f) and (g) for the named executives is required by the SEC rules. The amounts in these columns do not represent either the historical or anticipated future level of appreciation of our Common Stock.

The following table indicates for each of the named executives the number and value of exercisable and unexercisable options and SARs as of December 31, 2003.

Aggregated Option and SAR Exercises in 2003 and FY-End Option/SAR Value

(a) Name	(b) Shares Acquired on Exercise (#)	(c) Realized Value ($)	(d) Number of Unexercised Options and SARs at 12/31/03 (#) - Exercisable (ex)/ Unexercisable (unex)		(e) Value of Unexercised In-the-Money Options and SARs at 12/31/03 ($) - Exercisable (ex)/ Unexercisable (unex) *	
S.E. Moore	N/A	N/A	397,233	(ex)	$ 722,847	(ex)
			382,867	(unex)	1,862,750	(unex)
A.M. Strecker	35,000	$ 184,319	145,999	(ex)	112,548	(ex)
			169,901	(unex)	830,377	(unex)
P.B.Delaney	N/A	N/A	28,300	(ex)	42,167	(ex)
			154,800	(unex)	821,325	(unex)
J.R. Hatfield	N/A	N/A	79,433	(ex)	166,845	(ex)
			96,167	(unex)	473,801	(unex)
J.T. Coffman	16,700	$ 80,174	51,666	(ex)	41,737	(ex)
			57,834	(unex)	278,621	(unex)

* Share price on December 31, 2003 was $24.19. Options vest over 3 years with one-third becoming exercisable at the end of each year. Unexercisable options were granted on January 17, 2001 at a price of $22.50, January 16, 2002 at a price of $22.23, and January 27, 2003 at a price of $16.685. No SARs were granted in 2003.

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Long-Term Incentive Plans Awards In Last Fiscal Year

(a)	(b)	(c)	(d)	(e)	(f)
		Performance	Estimated future payouts under non-stock Price-based plans		
	Number of shares, units or other	or other period until maturation or	Threshold	Target	Maximum

Long-Term Incentive Plans Awards In Last Fiscal Year

Name	rights (#)(1)	payout(2)	(#)(2)	(#)(2)	(#)(2)
S.E. Moore	31,063	1/1/03-12/31/05	0	31,063	62,126
A.M. Strecker	13,879	1/1/03-12/31/05	0	13,879	27,758
P.B. Delaney	15,086	1/1/03-12/31/05	0	15,086	30,172
J.R. Hatfield	7,950	1/1/03-12/31/05	0	7,950	15,900
J.T. Coffman	4,616	1/1/03-12/31/05	0	4,616	9,232

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

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

PENSION PLAN TABLE

The Company and OG&E maintain a qualified non-contributory pension plan (the Retirement Plan) covering all employees who have completed one year of service. Subject to limitations imposed by the Employee Retirement Income Security Act of 1974 (ERISA), benefits payable under the Retirement Plan are based upon (i) the average of the five highest consecutive years of cash compensation (which for the executives named in the Summary Compensation Table prior to 1993 consisted solely of salaries and for subsequent years consists of salary and bonus) during an employee s last ten years prior to retirement and (ii) length of service. Social Security benefits are deducted in determining benefits payable under the Retirement Plan. Compensation covered by the Retirement Plan includes salaries, bonuses and overtime pay. Previously, benefits were reduced for each year prior to age 62 that an employee retired and were significantly reduced for retirement prior to age 55. The changes adopted in 2000 included: (i) elimination of the significant reduction for employees electing to retire before age 55, (ii) the addition of an alternative method of computing the reduction in benefits for an employee retiring prior to age 62, which alternative method 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, and (iii) the ability of an employee at time of retirement to receive, in lieu of an annuity, a lump-sum payment equal to the present value of the annuity. Also, for employees hired after January 31, 2000, the pension plan will be a cash balance plan, under which the Company annually will contribute to the employee s account an amount equal to 5% of the employee s annual compensation plus accrued interest. Employees hired prior to February 1, 2000 receive the greater of the cash balance formula or final average compensation formula. Retirement benefits are payable to participants upon normal retirement (at or after age 65) or early retirement (at or after attaining age 55 and completing five or more years of service), to former employees after reaching retirement age who have completed five or more years of service before terminating their employment and to participants after reaching retirement age upon total and permanent disability. As indicated above, the benefits payable under the Plan are subject to maximum limitations under ERISA. Should benefits for a participant at the time of retirement exceed the then permissible limits of ERISA, the Retirement Restoration Plan will provide benefits through a lump-sum distribution actuarially equivalent to the amounts that would have been payable to such participant annually under the Retirement Plan but for the ERISA limits. The Company and OG&E fund the estimated benefits payable under the Retirement Restoration Plan through contributions to a trust for the benefit of those employees who will be entitled to receive payments under the Retirement Restoration Plan.

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

Average Compensation 5 Highest Years	Years of Service at Retirement							
	10	15	20	25	30	35	40	45
$ 100,000	$ 12,859	$ 19,289	$ 25,718	$ 32,148	$ 38,578	$ 45,007	$ 51,437	$ 57,866
125,000	16,609	24,914	33,218	41,523	49,828	58,132	66,437	74,741
150,000	20,359	30,539	40,718	50,898	61,078	71,257	81,437	91,616
175,000	24,109	36,164	48,218	60,273	72,328	84,382	96,437	108,491
200,000	27,859	41,789	55,718	69,648	83,578	97,507	111,437	125,366
225,000	31,609	47,414	63,218	79,023	94,828	110,632	126,437	142,241

250,000	35,359	53,039	70,718	88,398	106,078	123,757	141,437	159,116
300,000	42,859	64,289	85,718	107,148	128,578	150,007	171,437	192,866
350,000	50,359	75,539	100,718	125,898	151,078	176,257	201,437	226,616
400,000	57,859	86,789	115,718	144,648	173,578	202,507	231,437	260,366
450,000	65,359	98,039	130,718	163,398	196,078	228,757	261,437	294,116
500,000	72,859	109,289	145,718	182,148	218,578	255,007	291,437	327,866
550,000	80,359	120,539	160,718	200,898	241,078	281,257	321,437	361,616
600,000	87,859	131,789	175,718	219,648	263,578	307,507	351,437	395,366
650,000	95,359	143,039	190,718	238,398	286,078	333,757	381,437	429,116
700,000	102,859	154,289	205,718	257,148	308,578	360,007	411,437	462,866
750,000	110,359	165,539	220,718	275,898	331,078	386,257	441,437	496,616
800,000	117,859	176,789	235,718	294,648	353,578	412,507	471,437	530,366
850,000	125,359	188,039	250,718	313,398	376,078	438,757	501,437	564,116
900,000	132,859	199,289	265,718	332,148	398,578	465,007	531,437	597,866
950,000	140,359	210,539	280,718	350,898	421,078	491,257	561,437	631,616
1,000,000	147,859	221,789	295,718	369,648	443,578	517,507	591,437	665,366

As of December 31, 2003, the credited years of service for the individuals listed in the Summary Compensation Table on page 16 are as follows: S. E. Moore - 29 years; A. M. Strecker - 32 years; P.B. Delaney - 1 year; J. R. Hatfield - 9 years; and J. T. Coffman - 33 years.

In 1993, OG&E adopted a SERP which is an unfunded supplemental plan that is not subject to the benefits limit imposed by ERISA. The plan generally provides for an annual retirement benefit at age 65 equal to 65% of the participant's average cash compensation during his or her final 36 months of employment, reduced by Social Security benefits, by amounts payable under the Retirement and Restoration Plans described above and by amounts received under pension plans from other employers. For a participant in the SERP who retires before age 65, the 65% benefit is reduced, with the reduction being 1% per year for ages 62 through 64, an additional 2% per year for ages 60 through 61, an additional 4% per year for ages 58 through 59 and an additional 6% per year for ages 55 through 57, so that a participant retiring at age 55 would receive 32% of his average cash compensation during his final 36 months, reduced by the deductions set forth above. Other than Mr. Delaney, no employee participated in the SERP during 2003. If selected to participate, none of the other individuals listed in the Summary Compensation Table on page 16 is expected to receive benefits under the SERP at normal retirement as the benefits payable to such individuals under the Retirement and Restoration Plans are expected to exceed the benefits payable under the SERP.

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EMPLOYMENT AGREEMENTS AND CHANGE OF CONTROL ARRANGEMENTS

Effective April 1, 2002, Mr. Peter Delaney entered into an employment agreement with the Company. The agreement extends through March 31, 2005. Under the terms of the agreement, Mr. Delaney will serve as an Executive Vice President of the Company and as the Chief Executive Officer of the Company's unregulated businesses. Mr. Delaney will be entitled to an annual base salary of not less than $400,000, subject to annual review and possible increase by the Board of Directors or the Compensation Committee. Mr. Delaney also will be entitled to participate in the Company's annual incentive plan and long-term stock incentive plan. Under the terms of the agreement, Mr. Delaney's annual target award under the annual incentive plan will be at least $240,000 (60% of his initial base salary) and Mr. Delaney's annual target award under the stock incentive plan will be at least $400,000 (100% of his initial base salary). In addition, Mr. Delaney will be entitled to (i) participate in all employee benefit plans and fringe benefits of the Company or an affiliate provided generally to executives of the Company, (ii) relocation expenses and (iii) participate in the Company's Supplemental Executive Retirement Plan (which is described on page 19).

Under the agreement, if Mr. Delaney's employment is terminated prior to March 31, 2005, due to death, disability or cause, he will be entitled to (i) his unpaid base salary through the date of termination, and (ii) accrued and unused vacation days, to the extent, and in the amount, if any, provided under the Company's usual policies and arrangements. These amounts are in addition to any benefits that Mr. Delaney at the time of his termination would be entitled to receive under the terms of any existing life insurance or disability policy or bonus, stock or other plan of the Company. If the Company terminates Mr. Delaney's employment prior to March 31, 2005 for any reason other than death, disability or cause, Mr. Delaney will be entitled to: (i) unpaid base salary through the date of termination, (ii) accrued and unused vacation days, to the extent, and in the amount, if any, provided under the Company's usual policies and arrangements, (iii) continued payment of base salary to March 31, 2005, and (iv) payment, within 15 days of termination, of annual and long-term incentive compensation, in amounts equal to the sum of the minimum annual target payouts, for the remainder of the term of the agreement. These payments are to be in lieu of any severance payouts to which Mr. Delaney may be entitled under any severance pay plan of the Company. If Mr. Delaney is entitled to benefits under this employment agreement and the change-of-control agreement described below, any payments or benefits to be paid under the employment agreement will be reduced by the amount of any comparable payments or benefits to which Mr. Delaney is or becomes entitled to under the terms of the change of control agreement. Mr. Delaney has agreed that he will not, without the prior written consent of the Board, compete with the Company during the term of the agreement and for one year following his termination.

The Company and OG&E also have entered into employment agreements with each officer of the Company and OG&E. Under the agreements, the officer is to remain an employee for a three-year period following a change of control of the Company (the "Employment Period"). During the Employment Period, the officer is entitled to (i) an annual base salary in an amount at least equal to his or her base salary prior to the change of control, (ii) an annual bonus in an amount at least equal to his or her highest bonus in the three years prior to the change of control and (iii) continued participation in the incentive, savings retirement and welfare benefit plans. The officer also is entitled to payment of expenses and provision of fringe benefits to the extent paid or provided to (a) such officer prior to the change of control or (b) other peer executives of the Company.

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

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COMPANY STOCK PERFORMANCE

The following graphs show a five-year comparison of cumulative total returns for the Company's Common Stock, the Dow Jones US Total Market Index, the Dow Jones US Electric Index, the S&P 500 Index and the S&P 500 Electric Utilities Index. For the last several years, the Company has used The Dow Jones US Total Market Index and the Dow Jones US Electric Index for comparative purposes. The Company has determined that the S&P Index and the S&P 500 Electric Utilities Index are more appropriate comparisons and, accordingly, for this year and future years, the Company expects to utilize such indices. The rules of the SEC require that if the Company switches to a new index, it also must show the results for the index used in the prior year's proxy statement. That is the reason we have included the two graphs below. The graphs assume that the value of the investment in the Company's Common Stock and each index was 100 at December 31, 1998, and that all dividends were reinvested. As of March 1, 2004, the closing price of the Company's Common Stock on the New York Stock Exchange was $25.82.

[PERFORMANCE GRAPH OMITTED]

	1998	1999	2000	2001	2002	2003
OGE Energy Corp.	100	69	95	95	78	114
Dow Jones US Electric Utilities Index	100	85	135	107	83	104
Dow Jones US Total Market Index	100	123	111	98	76	100

[PERFORMANCE GRAPH OMITTED]

	1998	1999	2000	2001	2002	2003
OGE Energy Corp.	100	69	95	95	78	114
Dow Jones US Electric Utilities Index	100	121	110	97	76	97
Dow Jones US Total Market Index	100	84	129	107	91	113

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SECURITY OWNERSHIP

The following table shows the number of shares of the Company s Common Stock beneficially owned on March 1, 2004, by each Director, by each of the Executive Officers named in the compensation table on page 16, 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	43,721	S.E. Moore	685,842

Luke R. Corbett	26,019	A.M. Strecker	261,341
William E. Durrett	24,688	P.B. Delaney	91,996
Martha W. Griffin	24,756	J.R. Hatfield	106,086
John D. Groendyke	27,323	J.T. Coffman	92,462
Robert Kelley	37,546		
Ronald H. White	32,615	All Executive Officers and Directors as a group (19 persons)	1,661,941
J.D. Williams	20,585		

(1) Ownership by each executive officer is less than .78% of the class, by each director other than Mr. Moore is less than .05% of the class and, for all executive officers and directors as a group, is less than 1.90% of the class. Amounts shown include shares for which, in certain instances, an individual has disclaimed beneficial interest. Amounts shown for executive officers include 1,513,806 shares of Common Stock representing their interest in shares held under the Company's Retirement Savings Plan, Officer's Deferred Compensation Plan, and Stock Incentive Plan for which in certain instances they have voting power but not investment power.

(2) Amounts shown for Messrs. Champlin, Corbett, Durrett, Groendyke, Kelley, White, and Williams and for Mrs. Griffin include, 37,595; 21,962; 16,595; 1,823; 21,813; 26,882; 4,825 and 15,363 common stock units, respectively, under the Directors' Deferred Compensation Plan.

(3) Includes shares subject to stock options granted under the Company's Stock Incentive Plan, exercisable within 60 days following March 1, 2004, as follows: each non-officer director except Mr. Groendyke, 3,733 shares; Mr. Groendyke, 0 shares; Mr. Moore, 572,399 shares; Mr. Strecker, 192,966 shares; Mr. Delaney, 89,333 shares; Mr. Hatfield, 87,266 shares; and Mr. Coffman, 68,566 shares.

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

EQUITY COMPENSATION PLAN INFORMATION

The following table provides certain information as of December 31, 2003 with respect to the shares of the Company s Common Stock that may be issued under the existing equity compensation plans:

	A	B	C
Plan Category	Number of Securities to be Issued upon Exercise of Outstanding Options	Weighted Average Price of Outstanding Options	Number of Securities Remaining Available for future issuances under equity compensation plans (excluding securities reflected in Column A)
Equity Compensation Plans Approved by Shareowners (1)	2,871,802	$21.63	2,700,000(2)
Equity Compensation Plans Not Approved by Shareowners	0	N/A	N/A

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

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

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SECTION 16(a) BENEFICIAL OWNERSHIP REPORTING COMPLIANCE

Under federal securities laws, our directors and executive officers are required to report, within specified monthly and annual due dates, their initial ownership in the Company s Common Stock and subsequent acquisitions, dispositions or other transfers of interest in such securities. We are required to disclose whether we have knowledge that any person required to file such a report may have failed to do so in a timely manner. Except as described in the immediately succeeding two sentences, to our knowledge, all of our directors and officers subject to such reporting obligations have satisfied their reporting obligations in full for 2003. Mr. Huneryager failed to timely file one report on Form 4 regarding the accrual of phantom stock units under the Company s deferred compensation plan. Mr. Huneryager filed the required Form 4 approximately five months late.

CHANGE OF INDEPENDENT PUBLIC ACCOUNTANTS

On May 16, 2002 the Board of Directors of the Company, upon recommendation of the Audit Committee, dismissed Arthur Andersen LLP as independent public accountants of the Company and OG&E and engaged Ernst & Young LLP as independent public accountants of the Company and OG&E for fiscal year 2002.

The audit reports of Arthur Andersen LLP on the Company s consolidated financial statements as of and for the fiscal years ended December 31, 2000 and 2001, did not contain any adverse opinion or disclaimer of opinion, nor were they qualified or modified as to uncertainty, audit scope or accounting principles.

During the fiscal years of the Company ended December 31, 2000 and 2001, and the subsequent interim period through May 16, 2002, there were no disagreements between the Company and Arthur Andersen LLP on any matter of accounting principles or practices, financial statement disclosure, or auditing scope or procedure, which disagreements, if not resolved to Arthur Andersen LLP s satisfaction, would have caused Arthur Andersen LLP to make reference to the subject matter of the disagreement in connection with its reports.

None of the reportable events described under Item 304(a)(1)(v) of Regulation S-K occurred within the fiscal years of the Company ended December 31, 2000 and 2001, or within the subsequent interim period through May 16, 2002.

The Company provided Arthur Andersen LLP with a copy of the foregoing disclosures. By copy of a letter dated May 21, 2002, Arthur Andersen LLP stated its agreement with such statements.

During the fiscal years of the Company ended December 31, 2000 and December 31, 2001, and the subsequent interim period through May 16, 2002, the Company did not consult with Ernst & Young LLP regarding any of the matters or events set forth in Items 304(a)(2)(i) and (ii) of Regulation S-K.

SHAREOWNER PROPOSALS

Any shareowner proposal intended to be included in the proxy statement for the Annual Meeting in 2005 must be received by the Company on or before December 2, 2004. 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 2005 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 Annual Report to Shareowners or proxy statement for your household, please contact Mellon Investor Services; P.O. Box 3337, 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 2003 Annual Report to Shareowners or this proxy statement, please call or write us at the following address or phone number: OGE Energy Corp. Shareowner Relations, 321 North Harvey, P.O. Box 321, Oklahoma City, OK 73101-0321 or phone 405-553-3211. 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 or write us at the following address or phone number: OGE Energy Corp. Shareowner Relations, 321 North Harvey, P.O. Box 321, Oklahoma City, OK 73101-0321 or phone 405-553-3211. 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.

MAP

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Annex A

OGE ENERGY CORP.
AUDIT COMMITTEE CHARTER

Purposes

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

Composition

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

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

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

2) Each Committee member shall be financially literate or shall become financially literate within a reasonable period of time after his or her appointment to the Committee. Additionally, at least one member of the Committee shall have accounting or related financial management expertise sufficient to meet the criteria of a financial expert within the meaning of Section 407 of the Sarbanes- Oxley Act of 2002 and any rules promulgated thereunder by the SEC. The Board of Directors shall determine, in its business judgment, whether a member is financially literate and whether at least one member has the requisite accounting or financial management expertise and meets the

financial expert criteria of Section 407 of the Sarbanes-Oxley Act of 2002 and any rules promulgated thereunder by the SEC. The designation or identification of a person as an audit committee financial expert shall not (a) impose on such person any duties, obligations or liability that are greater than the duties, obligations and liability imposed on such person as a member of the Audit Committee and Board of Directors in the absence of such designation or identification, or (b) affect the duties, obligations or liability of any other member of the Audit Committee or Board of Directors.

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

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

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

Duties and Responsibilities

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

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

In performing its responsibilities, the Committee shall:

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

2) Review and Discuss the Auditors' Quality Control: The Committee is to, at least annually, obtain and review a report by the independent auditors describing (a) the audit firm's internal quality control procedures, (b) any

material issues raised by the most recent internal quality control review, or peer review, of the firm, or by any inquiry or investigation by governmental or professional authorities, within the preceding five years, respecting one or more independent audits carried out by the firm, and (c) any steps taken to deal with any such issues.

3) Review and Discuss the Independence of the Auditors: In connection with the retention of the Company's independent auditors, the Committee is to, at least annually, review and discuss the information and reports provided by management or the auditors relating to the independence of the audit firm, including, among other things, information related to the non-audit services provided and expected to be provided by the auditors and other relationships between the independent auditors and the Company. The Committee is responsible for (a) ensuring that the independent auditors submit at least annually to the Committee a formal written statement delineating all relationships between the auditors and the Company consistent with applicable independence standards, (b) engaging in a dialogue with the auditors with respect to any disclosed relationship or services that may impact the objectivity and independence of the auditors, and (c) taking appropriate action in response to the auditors' report to satisfy itself of the auditors' independence. In connection with the Committee's evaluation of the independent auditors, the Committee shall review and evaluate the lead partner of the independent auditors and take such steps as may be required by law with respect to the identification and regular rotation of the audit partners serving

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on the Company's audit engagement team. The Committee also will consider whether, in order to assure continuing auditors' independence, it is appropriate to adopt a policy of rotating the independent auditing firm on a regular basis.

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

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

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

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

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

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

executive.

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

11) Review and Discuss the Systems of Internal Accounting Controls: The Committee is to review and discuss with the independent auditors, the senior internal auditing executive, the General Counsel and, if and to the extent deemed appropriate by the Chair of the Committee, members of their respective staffs the adequacy of the Company's internal accounting controls, the Company's financial, auditing and accounting organizations and personnel, and the Company's policies and compliance procedures with respect to business practices, which shall include the disclosures regarding internal controls and matters required to be reported to the Committee by Sections 302 and 404 of the Sarbanes-Oxley Act of 2002 and any rules promulgated thereunder by the SEC.

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

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13) Review and Discuss the Audit Results: The Committee is to review and discuss with the independent auditors (A) the report of their annual audit, or proposed report of their annual audit, (B) the accompanying management letter, if any, (C) the reports of their reviews of the Company's interim financial statements conducted in accordance with Statement on Auditing Standards No. 71, and (D) the reports of the results of such other examinations outside of the course of the independent auditors' normal audit procedures that the independent auditors may from time to time undertake. The foregoing shall include the reports required by Section 204 of the Sarbanes-Oxley Act of 2002 and any rules promulgated thereunder by the SEC and, as appropriate, a review of (a) major issues regarding (i) accounting principles and financial statement presentations, including any significant changes in the Company's selection or application of accounting principles and (ii) the adequacy of the Company's internal controls and any special audit steps adopted in light of material control deficiencies, (b) analyses prepared by management and/or the independent auditors setting forth significant financial reporting issues and judgments made in connection with the preparation of the financial statements, including analyses of the effects of alternative GAAP methods on the financial statements, and (c) the effect of regulatory and accounting initiatives, as well as off-balance sheet structures, on the financial statements of the Company.

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

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

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

17) Establish Procedures for Complaints Regarding Financial Statements or Accounting Policies: The Committee is to establish procedures for (A) the receipt, retention, and treatment of complaints received by the Company from employees regarding accounting, internal accounting controls, or auditing matters; and (B) the confidential, anonymous submission by employees of the Company of concerns regarding questionable accounting or auditing

matters as required by Section 301 of the Sarbanes-Oxley Act of 2002 and the rules and listing requirements promulgated thereunder by the SEC and the NYSE. The Committee is to discuss with management and the independent auditors any correspondence with regulators or governmental agencies and any complaints or concerns regarding the Company's financial statements or accounting policies.

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

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

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

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

Meetings

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

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

Resources and Authority

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

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

Audit Committee Report

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

Annual Review

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

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

OG&E

OGE Energy Corp.

2003 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 management of both electricity and natural gas 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 and 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 and trading of natural gas (collectively, Enogex s businesses). Enogex s focus is to utilize its gathering, processing, transportation and storage capacity to execute physical, financial and service transactions to capture revenues across different commodities, locations or time periods. The vast majority of Enogex s natural gas gathering, processing, transportation and storage assets are located in the major gas producing basins of Oklahoma. Through a 75 percent interest in the NOARK Pipeline System Limited Partnership, Enogex also owns a controlling interest in and operates the Ozark Gas Transmission System (Ozark), a FERC regulated interstate pipeline that extends from southeast Oklahoma through Arkansas to southeast Missouri. Enogex was previously engaged in the exploration and production of natural gas, however, this portion of Enogex s business, along with interests in certain gas gathering and processing assets in Texas, were sold in 2002 and in the first quarter of 2003 and are reported in the Consolidated Financial Statements as discontinued operations.

Company Strategy

In early 2002, the Company completed a review of its business strategy that was largely driven by the anticipated deregulation of the retail electric markets in Oklahoma and Arkansas. Due to a variety of factors, including the current efforts to repeal the Oklahoma Electric Restructuring Act of 1997 and the recent repeal of the Restructuring Law in Arkansas, the Company does not anticipate that deregulation of the electricity markets in Oklahoma or Arkansas will occur in the foreseeable future. The strategic direction of the Company has been revised to reflect these developments. As a result, the Company expects potentially slower earnings growth than associated with deregulation but with less variability of those earnings.

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The Company s revised business strategy will utilize the diversified asset position of OG&E and Enogex to provide energy products and services to customers primarily in the south central United States. The Company will focus on those products and services with limited or manageable commodity exposure. The Company intends for OG&E to continue as a vertically integrated utility engaged in the generation, transmission and the distribution of electricity and to represent over time approximately 70 percent of the Company s consolidated assets. The remainder of the Company s consolidated assets will be in Enogex s businesses. At December 31, 2003, OG&E and Enogex represented approximately 61 percent and 35 percent, respectively, of the Company s consolidated assets. The remaining four percent of the Company s consolidated assets were primarily at the holding company. In addition to the incremental growth opportunities that Enogex provides, the Company believes that Enogex s risk management capabilities, commercial skills and market information provide value to all of the Company s businesses. Federal regulation in regard to the operations of the wholesale power market may change with the evolving policy at the FERC. In addition, Oklahoma and Arkansas legislatures and utility commissions may propose changes from time to time that could subject utilities to market risk. Accordingly, the Company is applying risk management practices to all of its operations in an effort to mitigate the potential adverse effect of any future regulatory changes.

In the near term, OG&E plans on increasing its investment and growing earnings largely through the acquisition of electric generation (New Generation). As discussed in more detail below, in August 2003, OG&E signed an asset purchase agreement to acquire NRG McClain LLC s 77 percent interest in the 520 megawatt (MW) NRG McClain Station (the McClain Plant). In December 2003, the FERC delayed approval of the acquisition citing market power concerns. On January 15, 2004, the FERC administrative law judge in charge of the hearing and the parties to the case agreed to a procedural schedule that would produce a decision on the McClain Plant acquisition no sooner than the third quarter of 2004. OG&E subsequently withdrew its request before the OCC to increase its rates by approximately $91 million annually to cover the costs of the acquisition. Despite the delay at the FERC, an agreement to purchase power from the McClain Plant is enabling OG&E to honor the customer savings as outlined in the agreed settlement of OG&E s rate case (the Settlement Agreement). The Company will continue to monitor the FERC s recent shift in policy regarding market power issues around the McClain Plant acquisition to determine the practicability of future power plant purchases in addition to purchased power contracts. See Overview Pending Acquisition of Power Plant for a further discussion including a potential $2.1 million per month rate reduction. OG&E also plans to increase its capital expenditures in the foreseeable future for electric system reliability upgrades which is consistent with our commitment to our Customer Savings and Reliability Plan outlined in OG&E s rate case filed with the OCC on October 31, 2003.

OG&E currently has contracts with qualified cogeneration facilities and small power production producers (QF contracts) for the purchase of 540 MWs, all of which expire in the next one to five years. The Company will continue reviewing all of the supply alternatives to replace expiring QF contracts that minimize the total cost of generation to our customers. Accordingly, OG&E will continue to explore opportunities to build or buy power plants in order to serve its native load. As a result of the high volatility of current natural gas prices and the

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increase in natural gas prices, OG&E will also assess the feasibility of constructing additional base load coal-fired units.

Enogex initiated a program in 2002 to improve its financial profile and performance. Since January 1, 2002, Enogex has sold assets and received net sales proceeds of approximately $101.3 million, reduced debt by approximately $164.9 million or 22 percent, reduced its number of employees by approximately 12 percent, reorganized its operations and restructured its senior management team. In addition to focusing on growing its earnings, Enogex managed its commodity price and earnings volatility exposures and minimized its exposure to keep whole processing arrangements. Enogex s profitability increased significantly in 2003 due to the performance improvement plan initiated in 2002. While the Company believes substantial progress has been achieved, additional opportunities remain. Enogex continues to review its work processes, evaluate the rationalization of assets, negotiate better terms for both new contracts and replacement contracts, manage costs and pursue opportunities for organic growth, all in an effort to further improve its cash flow and net income.

In addition to these ongoing efforts, in 2003 Enogex began a major upgrade of its information systems that is expected to be substantially completed by the end of 2004. The Company believes that these upgrades will be a major step towards obtaining the data required to allow it to capture available economic opportunities on its assets, provide improved customer service and enable management to more accurately determine the earnings potential of its various assets and service offerings.

Other efforts at Enogex during 2003 included improvements to its two storage fields. The repair project at the Wetumka Storage Facility (formerly known as Greasy Creek) was designed to mitigate potential gas migration, and the remediation program at the Stuart Storage Facility (once completed) is intended to prevent water encroachment in the field. During 2003, approximately $0.5 million was spent and expensed on the Wetumka Storage Facility project and approximately $2.4 million in capital expenditures was spent on the Stuart Storage Facility project; the Company expects no material future expenditures at the Wetumka Storage Facility and expenditures of less than $1.5 million for the Stuart Storage Facility.

Forward-Looking Statements

Except for the historical statements contained herein, the matters discussed in the following discussion and analysis, including the discussion in 2004 Outlook , are forward-looking statements that are subject to certain risks, uncertainties and assumptions. Such forward-looking statements are intended to be identified in this document by the words anticipate , believe , estimate , expect , intend , objecti plan , possible , potential and similar expressions. Actual results may vary materially. Factors that could cause actual results to differ materially include, but are not limited to: general economic conditions, including the availability of credit, actions of ratings agencies and their impact on capital expenditures; the Company s ability and the ability of its subsidiaries to obtain financing on favorable terms; prices of electricity, natural gas and natural gas liquids, each on a stand-alone basis and in relation to each other; business conditions in the energy industry; competitive factors including the extent and timing of the entry of additional competition in the markets served by the Company; unusual

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weather; state and federal legislative and regulatory decisions and initiatives; changes in accounting standards, rules or guidelines; creditworthiness of suppliers, customers, and other contractual parties; completion of the pending acquisition of a power plant; an adverse decision by the OCC requiring OG&E to reduce its rates and the other risk factors listed in the reports filed by the Company with the Securities and Exchange Commission.

Overview

General

The following discussion and analysis presents factors which affected the Company s consolidated results of operations for the years ended December 31, 2003, 2002 and 2001 and the Company s consolidated financial position at December 31, 2003 and 2002. 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.

Enogex previously was engaged in the exploration and production of natural gas (the E&P business). Since January 1, 2002, Enogex has sold all of its E&P business along with certain gas gathering and processing assets that were owned by Enogex through its interest in the NuStar Joint Venture (NuStar) and its interest in Belvan Corp., Belvan Limited Partnership and Todd Ranch Limited Partnership (Belvan). As required by accounting principles generally accepted in the United States, these dispositions have been reported as discontinued operations for the years ended December 31, 2003, 2002 and 2001 in the Consolidated Financial Statements.

Operating Results

2003 compared to 2002. The Company reported net income of approximately $129.8 million, or $1.58 per diluted share, and $90.8 million, or $1.16 per diluted share, for the years ended December 31, 2003 and 2002, respectively. The increase in net income during 2003 as compared to 2002 was primarily due to lower impairment charges and higher gross margin on revenues (gross margin) in all of Enogex s businesses and lower interest expenses at the holding company. These increases were partially offset by lower earnings at OG&E. The Company s results of operations for the years ended December 31, 2003 and 2002 include a loss of approximately $0.4 million, or $0.00 per diluted share, and income of approximately $9.8 million, or $0.12 per diluted share, respectively, from the discontinued operations discussed above. See Results of Operations Enogex Discontinued Operations below for a further discussion.

OG&E reported net income of approximately $115.4 million, or $1.41 per diluted share, and $126.1 million, or $1.61 per diluted share, for the years ended December 31, 2003 and 2002, respectively. The decrease in net income during 2003 as compared to 2002 was primarily attributable to lower electric rates as a result of the $25 million electric rate reduction that went into effect in Oklahoma on January 6, 2003, weaker weather-related demand and higher

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operating and maintenance expenses partially offset by customer growth in OG&E s service territory.

Enogex s operations, including discontinued operations, reported net income of approximately $26.9 million, or $0.33 per diluted share, for the year ended December 31, 2003 as compared to a net loss of approximately $21.7 million, or $0.28 per diluted share, for the year ended December 31, 2002. This improvement during 2003 as compared to 2002 was primarily attributable to lower impairment charges and higher gross margins in all of Enogex s businesses from, among other things, improved management of pipeline system fuel, increased levels of firm transportation revenues, improved processing results and the negotiation of both new contracts and replacement contracts at better terms that resulted in increases in gathering fees and reductions in the purchase price of gas. Also contributing to Enogex s improvement were gains from asset sales, lower net interest expense and lower operating and maintenance expenses.

As stated above, Enogex s E&P business, its interest in NuStar and its interest in Belvan have been reported as discontinued operations for the years ended December 31, 2003, 2002 and 2001 in the Consolidated Financial Statements as these assets have been sold. The Company s results of operations for the years ended December 31, 2003 and 2002 include a loss of approximately $0.4 million, or $0.00 per diluted share, and income of approximately $9.8 million, or $0.12 per diluted share, respectively, from the discontinued operations discussed above. This decrease was attributable to the sale of Enogex s E&P business, NuStar and Belvan during 2002 and in the first quarter of 2003, higher income tax expense due to tax credits from Enogex s E&P business not being realized as a result of a tax accounting method change and recording an additional charge related to the sale of NuStar during the third quarter of 2003. See Results of Operations Enogex Discontinued Operations below for a further discussion.

The results of the holding company reflect a loss of $0.16 per diluted share and a loss of $0.17 per diluted share for the years ended December 31, 2003 and 2002, respectively. The improvement is primarily due to lower interest charges and a higher income tax benefit partially offset by higher other miscellaneous expenses.

2002 compared to 2001. The Company reported net income of approximately $90.8 million, or $1.16 per share, and $100.6 million, or $1.29 per share, for the years ended December 31, 2002 and 2001, respectively. The decrease in net income during 2002 as compared to 2001 was primarily due to impairment losses of $0.39 per share in the fourth quarter of 2002 for Enogex and the Company. Excluding impairment charges, the Company s earnings in 2002 would have been $1.55 per share compared to $1.34 per share in 2001, when the Company reported a $0.05 per share impairment charge. The Company s results of operations for the years ended December 31, 2002 and 2001 include income of approximately $9.8 million, or $0.12 per share, and income of approximately $6.7 million, or $0.09 per share, respectively, from the discontinued operations discussed above. See Results of Operations Enogex Discontinued Operations below for a further discussion.

OG&E reported net income of approximately $126.1 million, or $1.61 per share, and $121.2 million, or $1.55 per share, for the years ended December 31, 2002 and 2001, respectively. The increase in net income during 2002 as compared to 2001 is primarily

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attributable to lower operating and maintenance expenses, lower interest expenses and increased growth in OG&E s service territory partially offset by lower levels of natural gas transportation cost recovered, lower recoveries of fuel costs from Arkansas customers, loss of revenue resulting from the January 2002 ice storm, lower sales to other utilities and power marketers (off-system sales), milder weather and higher depreciation expense.

Enogex s operations, including discontinued operations, reported a net loss of approximately $21.7 million, or $0.28 per share, and a loss of $5.0 million, or $0.06 per share, for the years ended December 31, 2002 and 2001, respectively. The reduced earnings during 2002 as compared to 2001 were primarily attributable to impairment losses of $0.38 per share in the fourth quarter of 2002 related to the disposition of natural gas processing plants and compression assets that were no longer needed in Enogex s business. Absent impairment charges in 2002 and 2001 and including discontinued operations, Enogex would have earned $0.10 per share in 2002 compared with a loss of $0.01 per share in 2001. This improvement was primarily from the transportation and storage business as a result of additional firm revenues from new long-term contracts to merchant electric generation facilities and increased storage revenues. Additionally, better fuel recoveries and lower interest expense contributed to the improvement and were only partially offset by lower volumes in gathering and processing.

As stated above, Enogex s E&P business, its interest in NuStar and its interest in Belvan have been reported as discontinued operations for the years ended December 31, 2003, 2002 and 2001 in the Consolidated Financial Statements as these assets have been sold. The Company s results of operations for the years ended December 31, 2002 and 2001 include income of approximately $9.8 million, or $0.12 per share, and income of approximately $6.7 million, or $0.09 per share, respectively. The increase was primarily related to a higher gross margin on natural gas liquids sales, an impairment charge recorded in 2001 for Belvan, net gains on the sale of certain of these assets in 2002, lower depreciation expense and lower operating and maintenance expenses partially offset by a lower gross margin on natural gas sales. See Results of Operations Enogex Discontinued Operations below for a further discussion.

The results of the holding company reflect a loss of $0.17 per share and a loss of $0.20 per share for the years ended December 31, 2002 and 2001, respectively. The reduced loss was primarily attributable to lower interest expenses partially offset by a lower income tax benefit and an impairment loss in the fourth quarter of 2002 related to the Company s aircraft.

2002 Settlement Agreement

On October 11, 2002, OG&E, the OCC Staff, the Oklahoma Attorney General and other interested parties agreed to the Settlement Agreement of OG&E s rate case. The administrative law judge subsequently recommended approval of the Settlement Agreement and on November 22, 2002, the OCC signed a rate order containing the provisions of the Settlement Agreement. The Settlement Agreement provides 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 New Generation of not less than 400 MWs to be integrated into OG&E s generation system; and (iv) recovery by OG&E, over three years, of the

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$5.4 million in deferred operating costs, associated with the January 2002 ice storm, through OG&E s rider for off-system sales. Previously, OG&E had a 50/50 sharing mechanism in Oklahoma for any off-system sales. The Settlement Agreement provided that the first $1.8 million in annual net profits from OG&E s off-system sales will go to OG&E, the next $3.6 million in annual net profits from off-system sales will go to OG&E s Oklahoma customers, and any net profits of 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. If any of the $5.4 million is not recovered at the end of the three years, the OCC will authorize the recovery of any remaining costs.

Pending Acquisition of Power Plant

As part of the 2002 Settlement Agreement with the OCC, OG&E undertook to acquire New Generation of not less than 400 MWs. The acquisition of a 77 percent interest in the McClain Plant would clearly constitute an acquisition of such New Generation under the Settlement Agreement. OG&E expects this New Generation, including the interim purchase power agreement, will provide savings, over a three-year period, in excess of $75.0 million to its Oklahoma customers. These savings will be derived from: (i) the avoidance of purchase power contracts otherwise needed; (ii) replacing an above market cogeneration contract with PowerSmith Cogeneration Project, L.P. (PowerSmith) when it can be terminated at the end of August 2004; and (iii) fuel savings associated with operating efficiencies of the new plant. These savings, while providing real savings to Oklahoma customers, are not expected to affect the profitability of OG&E because OG&E s rates would not need to be reduced to accomplish these savings. As indicated in the Settlement Agreement, OG&E is required to provide monthly reports, for a period of 36 months after the acquisition, to the OCC Staff, documenting and providing proof of savings experienced by OG&E s 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 have an obligation to credit its Oklahoma customers any unrealized savings below $75.0 million as determined at the end of the 36-month period, which shall be no later than December 31, 2006. PowerSmith has filed an application with the OCC seeking to compel OG&E to continue purchasing power from PowerSmith s qualified cogeneration facility under the Public Utility Regulatory Policy Act of 1978 (PURPA) at a price that would include an avoided capacity charge equal to the lesser of (i) the rate currently specified in the power purchase agreement between OG&E and PowerSmith or (ii) the avoided cost of the McClain Plant. OG&E does not believe that this matter should be heard at the OCC at this time and that the avoided cost requested by PowerSmith is too high. In the event PowerSmith is ultimately successful and OG&E is required to sign a purchase power agreement, it could negatively affect OG&E s ability to achieve the targeted $75 million three-year customer savings under the existing terms of the Settlement Agreement. PowerSmith and OG&E have been holding discussions to determine if mutually agreeable terms can be reached for a power contract between the companies providing for capacity payments to the PowerSmith facility.

In the event OG&E did not acquire the New Generation by December 31, 2003, the Settlement Agreement requires OG&E to 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. However, if OG&E purchases the New Generation subsequent to January 1, 2004, the credit to Oklahoma

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customers will terminate in the first month that the New Generation begins initial operations and any previously-credited amounts to Oklahoma customers will be deducted in the determination of the $75.0 million targeted savings.

On August 18, 2003, OG&E signed an asset purchase agreement to acquire NRG McClain LLC s 77 percent interest in the McClain Plant. The acquisition of this interest in the McClain Plant would clearly constitute an acquisition of New Generation under the Settlement Agreement. The purchase price for the interest in the McClain Plant is approximately $159.9 million, subject to adjustment for prepaid gas and property taxes. The McClain Plant includes natural gas-fired combined cycle combustion turbine units and is located near Newcastle, Oklahoma in McClain County, Oklahoma. The McClain Plant began operating in 2001. The owner of the remaining 23 percent in the McClain Plant is the Oklahoma Municipal Power Authority (OMPA).

Closing is subject to customary conditions including receipt of regulatory approval by the FERC. The asset purchase agreement, as amended, provides that, unless extended, either party has the right to terminate the contract if the closing does not occur on or before March 16, 2004. Because the current owner of the McClain Plant has filed for bankruptcy protection, the acquisition also was subject to approval by the bankruptcy court. As part of the bankruptcy approval process, NRG McClain LLC s interest in the plant was subject to an auction process and on October 28, 2003, the bankruptcy court approved the sale of NRG McClain LLC s interest in the plant to OG&E. Several parties have filed interventions at the FERC opposing OG&E s application under Section 203 of the Federal Power Act to acquire NRG McClain s interest in the power plant or, alternatively, requesting the FERC to delay approving such acquisition. OG&E believed that its application met the standards under Section 203 set forth by the FERC and that its application would be approved. On December 18, 2003, the FERC shifted its policy regarding market power issues, raised wholesale market power concerns and ordered a hearing regarding OG&E s acquisition of the McClain Plant. The FERC action did not reject OG&E s request to purchase the McClain Plant, but demonstrated that OG&E must address certain issues. On January 20, 2004, OG&E filed a petition for re-hearing of the FERC s December 18, 2003 order which included new mitigation measures that were designed to allow for prompt approval of the transaction. That request is still pending before the FERC. OG&E has no indication whether the FERC will accept those proposed mitigation measures. On March 2, 2004, OG&E filed testimony and exhibits with the FERC administrative law judge. The testimony and exhibits indicate that, if the case proceeds to hearing, the wholesale market power issues that the FERC raised in the December 18, 2003 order may be resolved by the minimal mitigation measures.

Assuming the acquisition occurs, OG&E expects to operate the plant in accordance with a joint ownership and operating agreement with the OMPA. Under this agreement, OG&E would operate the facility, and OG&E and the OMPA would be entitled to the net available output of the plant based on their respective ownership percentages. All fixed and variable costs, except fuel and gas transportation costs, would be shared in proportion to the respective ownership interests. Fuel and gas transportation costs would be shared based on consumption. OG&E expects to utilize its portion of the output, 400 MWs, to serve its native load. As provided in the Settlement Agreement, pending approval of a request to increase base rates to

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recover the investment in the plant, OG&E will have the right to accrue a regulatory asset, for a period not to exceed 12 months subsequent to the acquisition, consisting of the non-fuel operation and maintenance expenses, depreciation, cost of debt associated with the investment and ad valorem taxes. Upon approval by the OCC of OG&E s request, all prudently incurred costs accrued through the regulatory asset within the 12-month period will be included in OG&E s prospective cost of service.

Despite the delay at the FERC, an agreement to purchase power from the McClain Plant is enabling OG&E to honor the customer savings as outlined in the Settlement Agreement. On January 8, 2004, OG&E filed an application with the OCC and requested that the OCC confirm the steps that OG&E has taken to comply with the Settlement Agreement will result in customer savings being delivered beginning January 1, 2004, and that no further rate reduction is necessary. Various parties have intervened opposing OG&E s request. If the OCC does not agree with OG&E s request, OG&E will be required to reduce electric rates to its Oklahoma customers by approximately $2.1 million per month and would expect to reduce expenditures for planned electric system reliability upgrades. The OCC has scheduled a hearing on April 19, 2004 for action in this case.

Assuming that OG&E acquires the McClain Plant, OG&E expects to fund the acquisition with a combination of a capital contribution from the Company, funded in part by the Company s equity issuance in 2003, and the issuance of long-term debt by OG&E.

2003 Rate Case

On September 15, 2003, OG&E filed with the OCC a notice of intent to seek an annual increase in its rates to its Oklahoma customers of more than one percent. The notice listed the following, among others, as major issues to be addressed in its application: (i) the acquisition of New Generation in accordance with the Settlement Agreement; (ii) increased capital expenditures for efficiency improvements and reliability enhancements to ensure fuel costs are minimized; and (iii) increased pension, medical and insurance costs. On October 31, 2003, OG&E filed a request with the OCC to increase its rates by approximately $91 million annually. The increase was intended to pay for its pending acquisition of a 77 percent interest in the McClain Plant, allow for investment in electric system reliability and address rising business costs. The rate plan would have reduced rates for schools and more than 80,000 small businesses and non-profit organizations. On January 15, 2004, OG&E filed an application to withdraw its request for a $91 million rate increase due to the delay at FERC in receiving the necessary approvals to complete the acquisition of the McClain Plant, which was a significant part of this rate case. An order dismissing the case was issued by the OCC on January 30, 2004. On December 18, 2003, the FERC issued an order setting for hearing OG&E s proposed acquisition of the McClain Plant and on January 15, 2004, the FERC administrative law judge in charge of the hearing and the parties to the case agreed to a procedural schedule that would produce a decision on the McClain Plant acquisition no sooner than the third quarter of 2004. OG&E expects to file another rate case in the near future to recover increased operating and capital expenditures.

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Gas Transportation and Storage Agreement

As part of the Settlement Agreement, OG&E also agreed to consider competitive bidding for gas transportation service to its natural gas-fired generation facilities pursuant to the terms set forth in the Settlement Agreement. OG&E believes that in order for it to achieve maximum coal generation and ensure reliable electric service, it must have firm no-notice load following service for both gas transportation and gas storage. This type of service is required to satisfy the daily swings in customer demand placed on OG&E s system and still permit natural gas units to not impede coal energy production. OG&E also believes that gas storage is an integral part of providing gas supply to OG&E s generation facilities. Accordingly, OG&E evaluated its competitive bid options in light of these circumstances. OG&E s evaluation clearly demonstrates that the Enogex integrated gas system provides superior firm no-notice load following service to OG&E that is not available from other companies serving the OG&E marketplace. On April 29, 2003, OG&E filed an application with the OCC in which OG&E advised the OCC that, after careful consideration, competitive bidding for gas transportation was rejected in favor of a new intrastate 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. During 2003, OG&E paid Enogex approximately $44.7 million for gas transportation and storage services. Based upon requests for information from intervenors, OG&E has requested from Enogex and Enogex has agreed to retain a cost of service consultant to assist in the preparation of testimony related to this case. On January 30, 2004, the OCC issued a procedural schedule for this case. A hearing is scheduled August 10-11, 2004 and an OCC order in the case is expected by the end of 2004. OG&E believes the amount currently paid to Enogex for no-notice load following transportation and storage services is fair, just and reasonable. If any amounts paid by OG&E are found not to be recoverable, OG&E believes such amount would not be material.

Security Enhancements

On April 8, 2002, OG&E filed a joint application with the OCC requesting approval for security investments and a rider to recover these costs from the ratepayers. On August 14, 2002, OG&E filed testimony with the OCC outlining proposed expenditures and related actions for security enhancement and a proposed recovery rider. Attempting to make security investments at the proper level, OG&E has developed a set of guidelines intended to minimize long-term or widespread outages, minimize the impact on critical national defense and related customers, maximize the ability to respond to and recover from an attack, minimize the financial impact on OG&E that might be caused by an attack and accomplish these efforts with minimal impact on ratepayers. The OCC Staff retained a security expert to review the report filed by OG&E. OG&E currently expects that hearings will be held in early 2004.

On October 17, 2003, the OCC filed a notice of inquiry to consider the issues related to the role of the OCC and Oklahoma regulated companies in addressing the security of the electrical system infrastructure and key assets. On March 4, 2004, the OCC deliberated the notice of inquiry and directed the OCC Staff to file a rulemaking proceeding for each utility industry regarding security of the electrical system infrastructure and key assets.

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OG&E has been and will continue to be affected by competitive changes to the utility industry. Significant changes already have occurred and additional changes are being proposed to the wholesale electric market. Although it appears unlikely in the near future that changes will occur to retail regulation in the states served by OG&E due to the significant problems faced by California in its electric deregulation efforts and other factors, significant changes are possible, which could significantly change the manner in which OG&E conducts its business.These developments at the federal and state levels are described in more detail below under Electric Competition; Regulation.

Asset Disposals

Enogex sold its interest in NuStar for approximately $37.0 million in February 2003. The Company recognized approximately a $1.4 million after tax gain related to the sale of these assets in the first quarter of 2003. The final accounting for the NuStar sale was completed in the third quarter of 2003 which resulted in an additional charge of approximately $0.2 million after tax which was recorded in the third quarter of 2003. The final accounting is subject to approval by all parties to the sale of the joint venture interest. These items are recorded in Income from Discontinued Operations in the accompanying Consolidated Statements of Income. These assets were part of the Natural Gas Pipeline segment.

Enogex sold approximately 29 miles of transmission lines of the Ozark pipeline, in which an Enogex subsidiary owns a 75 percent interest, located in Pittsburg and Latimer counties in Oklahoma for approximately $10.0 million in January 2003. The Company recognized approximately a $5.3 million pre-tax gain and approximately $1.1 million in minority interest expense in the first quarter of 2003 related to the sale of these assets, which is recorded in Other Income and Other Expense, respectively, in the accompanying Consolidated Statements of Income. These assets were part of the Natural Gas Pipeline segment.

The Company sold its aircraft for approximately $5.8 million in August 2003. The Company recognized approximately a $0.1 million pre-tax loss related to the sale of the aircraft, which is recorded in Other Expense in the accompanying Consolidated Statements of Income. The aircraft was part of Other Operations.

2004 Outlook

General

The Company currently expects that consolidated earnings in 2004 will be between $1.40 and $1.50 per share, excluding any regulatory action that might affect the electric rates at OG&E. The Company expects improved performance from Enogex while at OG&E, financial performance will depend to a large extent on regulatory considerations. The 2004 outlook includes expected net income of between $113 million and $117 million at OG&E and between $27 million and $31 million at Enogex, while the holding company will likely post a net loss of approximately $16 million. During 2004, the Company expects cash flow from operations of between $300 million and $310 million. In 2004, OG&E plans to increase capital expenditures for electric system reliability upgrades. The Company has assumed approximately 88.0 million

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average common shares outstanding for 2004 which includes issuing approximately 2.0 million additional shares (approximately $50.0 million of common stock) through the Company s Automatic Dividend Reinvestment and Stock Purchase Plan (DRIP) in the second half of 2004. Additionally, funding for the Company s pension plan is expected to be approximately $56.0 million in 2004. In addition to issuing long-term debt to support the acquisition of New Generation, the Company also anticipates calling $200 million of 8.375 percent trust preferred securities at the holding company and replacing them with long-term debt. The replacement of the trust preferred securities will be dependent upon the interest rate environment, access to the capital markets and regulatory and other considerations. The 2004 outlook also includes approximately $6.2 million of additional interest expense at the holding company for unamortized debt expense associated with calling the trust preferred securities. Expected 2004 net income assumes a 38.7 percent effective tax rate.

OG&E

During 2004, OG&E anticipates slightly higher revenue than in 2003 based on sales growth of slightly less than two percent, normal weather and no change in base rates. Overall operating expenses are expected to grow at a rate of approximately 2.8 percent. OG&E also assumes lower short-term interest costs for 2004 and OG&E expects to increase capital expenditures to over $200 million for electric system reliability upgrades. Key factors affecting OG&E s 2004 net income will be the result of pending regulatory proceedings, weather, OG&E s ability to control operating and maintenance expenses and customer growth. If the OCC does not agree that OG&E is delivering the customer savings as outlined in the Settlement Agreement, OG&E may be required to credit to its Oklahoma customers approximately $2.1 million per month for each month that the New Generation is not in place. 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

Enogex manages its operations along three related businesses: transportation and storage; gathering and processing; and marketing and trading. In 2004, these businesses are expected to produce a gross margin of approximately $244 million, down from $253 million in 2003. The Company expects approximately 51 percent of Enogex s gross margin during 2004 to be generated from its transportation and storage business as compared to 55 percent in 2003. Approximately 74 percent of these gross margins are under firm contracts. Revenues in transportation and storage are primarily from gas transportation contracts with utilities in Oklahoma and Arkansas and independent power producers (IPP) in Oklahoma. Revenues in the transportation and storage business are expected to decrease due to lower recovery of prior under recovered fuel as the Company has lowered its fuel rate on the system partially offset by the full year impact of a storage contract. The Company expects its gathering and processing business to contribute approximately 41 percent of Enogex s gross margin in 2004 as compared to 36 percent in 2003. Revenues in gathering and processing are expected to increase in 2004 primarily due to continued efforts to increase margins from renegotiation of expiring contracts and reduced fuel expense offset by lower forecasted processing margins. Volumes are expected

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to remain flat from 2003. The Company has forecasted natural gas prices of approximately $4.50 per million British thermal unit (MMBtu), $0.51 per gallon average natural gas liquids prices and 200 new well connects in its gathering and processing business. The Company expects its marketing and trading business to contribute approximately eight percent of Enogex s gross margin in 2004 as compared to nine percent in 2003. Revenues in marketing and trading are expected to decrease in 2004 primarily due to a lack of the 2003 change in accounting principle discussed in Accounting Pronouncements partially offset by increased natural gas marketed volumes. Enogex also expects operating expenses to be flat in 2004 as increased operating expenses are offset by the impairment charge of $9.2 million that was recorded in 2003. Enogex also expects lower interest expense due to lower levels of long-term debt. Key factors affecting Enogex s 2004 net income will be gathering and processing volumes on the system, natural gas and natural gas liquids prices, commodity prices and the level of system fuel costs.

Enogex expects to continue to evaluate the strategic fit and financial performance of its assets in an effort to ensure a proper economic allocation of resources. The magnitude and timing of any impairment or gain on the disposition of assets that may be identified as not being strategic have not been determined.

Dividend Policy

The Company s dividend policy is determined by the Board of Directors and is based on numerous factors, including management s estimation of the long-term earnings power of its businesses. The target payout ratio for the Company is to pay out as dividends approximately 75 percent of its 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. While the dividend payout ratio is expected to exceed the target payout ratio in 2004, management after considering estimates of future earnings and numerous other factors, expects at this time that it will continue to recommend to the Board of Directors a continuance of the current dividend rate.

Results of Operations

				Percent Change From Prior Year	
(In millions, except per share data)	**2003**	2002	2001	2003	2002
Operating income	**$ 306.9**	$ 235.7	$ 270.9	30.2	(13.0)
Net income	**$ 129.8**	$ 90.8	$ 100.6	43.0	(9.7)
Basic average common shares outstanding	**81.8**	78.1	77.9	4.7	0.3
Diluted average common shares outstanding	**82.1**	78.2	77.9	5.0	0.4
Basic earnings per average common share	**$ 1.59**	$ 1.16	$ 1.29	37.1	(10.1)
Diluted earnings per average common share	**$ 1.58**	$ 1.16	$ 1.29	36.2	(10.1)
Dividends declared per share	**$ 1.33**	$ 1.33	$ 1.33	---	---

In reviewing its consolidated operating results, the Company believes that it is appropriate to focus on operating income as reported in its Consolidated Statements of Income as operating income indicates the ongoing profitability of the Company excluding unusual or infrequent items, the cost of capital and income taxes. Included in 2003 and 2002 operating

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income are pre-tax impairment charges of approximately $10.2 million and $50.1 million, respectively. These impairments, primarily for Enogex natural gas processing and compression assets that were no longer needed in Enogex s business, were made in accordance with accounting principles generally accepted in the United States. Operating income was approximately $306.9 million, $235.7 million and $270.9 million in 2003, 2002 and 2001, respectively. These amounts exclude the results of Enogex s E&P business, NuStar and Belvan, which as explained above, were sold in 2002 and in the first quarter of 2003 and which are reported as discontinued operations. See Enogex Discontinued Operations below for a further discussion.

Operating Income (Loss) by Business Segment

(In millions)	**2003**	2002	2001
OG&E (Electric Utility)	**$ 216.2**	$ 239.1	$ 236.6
Enogex (Natural Gas Pipeline) (A)	**91.2 (B)**	(3.0) (B)	34.4
Other Operations (C)	**(0.5)**	(0.4)	(0.1)
Consolidated operating income	**$ 306.9**	$ 235.7	$ 270.9

(A) Excludes discontinued operations.
(B) After recording pre-tax impairment charges of approximately $9.2 million and $48.3 million in 2003 and 2002, respectively.
(C) Other Operations primarily includes unallocated corporate expenses.

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

OG&E

(In millions)	**2003**	2002	2001

Operating revenues	**$1,517.1**	$ 1,388.0	$ 1,456.8
Fuel	**544.5**	435.8	485.8
Purchased power	**292.9**	260.0	280.7
Gross margin on revenues	**679.7**	692.2	690.3
Other operating expenses	**463.5**	453.1	453.7
Operating income	**$ 216.2**	$ 239.1	$ 236.6
System sales - MWH (A)	**25.0**	24.6	24.5
Off-system sales - MWH	**0.1**	0.3	0.4
Total sales - MWH	**25.1**	24.9	24.9

(A) Megawatt-hour

2003 compared to 2002. OG&E s operating income decreased approximately $22.9 million or 9.6 percent in 2003 as compared to 2002. The decrease in operating income was primarily attributable to lower electric rates as a result of the $25 million electric rate reduction that went into effect in Oklahoma on January 6, 2003, weaker weather-related demand, lower off-system sales and higher operating and maintenance expenses partially offset by customer growth in OG&E s service territory.

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Gross margin, which is operating revenues less cost of goods sold, was approximately $679.7 million in 2003 as compared to approximately $692.2 million in 2002, a decrease of approximately $12.5 million or 1.8 percent. The gross margin primarily decreased due to lower electric rates as a result of the $25 million electric rate reduction that went into effect in Oklahoma on January 6, 2003 (approximately $24.8 million). Gross margin also was reduced by approximately $2.0 million due to weaker weather-related demand. Lower off-system sales decreased the gross margin by approximately $1.9 million as off-system sales can vary based upon the supply and demand needs on OG&E s generation system. Partially offsetting these decreases in gross margin was an increase of approximately $17.5 million due to customer growth in OG&E s service territory.

Cost of goods sold for OG&E consists of fuel used in electric generation and purchased power. Fuel expense increased approximately $108.7 million or 24.9 percent in 2003 as compared to 2002 primarily due to a 29.4 percent increase in the average cost of fuel per kilowatt-hour (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 2003, OG&E s fuel mix was 77 percent coal and 23 percent natural gas. Though OG&E has a higher installed capability of generation from natural gas units of 55 percent, it has been more economical to generate electricity for our customers with lower priced coal. Purchased power costs increased approximately $32.9 million or 12.7 percent in 2003 as compared to 2002. The increase was primarily due to approximately a 28.2 percent increase in the volume of energy purchased primarily due to economic purchases.

Variances in the actual cost of fuel used in electric generation and certain purchased power costs, as compared to the fuel component included in the cost-of-service for ratemaking, are passed through to OG&E s customers through automatic fuel adjustment clauses. While the regulatory mechanisms for recovering fuel costs differ in Oklahoma and Arkansas, in both states the costs are passed through to customers and are intended to provide neither an ultimate benefit nor detriment to OG&E. The automatic fuel adjustment clauses are subject to periodic review by the OCC, the APSC and the FERC. The OCC, the APSC and the FERC have authority to review the appropriateness of gas transportation charges or other fees OG&E pays to Enogex. See Note 18 of Notes to Consolidated Financial Statements.

Other operating expenses, consisting of operating and maintenance expense, depreciation expense and taxes other than income, increased approximately $10.4 million or 2.3 percent in 2003 as compared to 2002. OG&E s operating and maintenance expense increased approximately $11.9 million or 4.2 percent in 2003 as compared to 2002. The increase was primarily due to approximately a $10.7 million increase in pension and benefit expenses in 2003 as compared to 2002, due to the general upward trend in these costs. Also contributing to the increase in operating and maintenance expenses was the recognition of approximately $5.4 million for costs incurred during the first quarter of 2002 in connection with the severe January 2002 ice storm being reported as a regulatory asset. These 2002 expenditures, incurred by field service personnel, would normally have been charged to maintenance expenses in 2002. The increased operating and maintenance expenses were partially offset by a decrease in bad debt expense of approximately $3.5 million due to improved collection efforts.

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Depreciation expense decreased approximately $1.3 million or 1.1 percent in 2003 as compared to 2002 due to a change made in the depreciation rate of production plant in 2003 as required by the Settlement Agreement.

2002 compared to 2001. OG&E s operating income increased approximately $2.5 million or 1.1 percent in 2002 as compared to 2001. The increase in operating income was primarily attributable to a slightly higher gross margin due to growth in electric usage in OG&E s service territory and lower operating and maintenance expenses partially offset by lower levels of natural gas transportation cost recovered, lower recoveries of fuel costs from Arkansas customers, loss of revenue resulting from the January 2002 ice storm, lower off-system sales and milder weather.

Gross margin was approximately $692.2 million in 2002 as compared to approximately $690.3 million in 2001, an increase of approximately $1.9 million or 0.3 percent. Growth in the number of customers in OG&E s service territory and the resulting increase in electric sales of approximately 2.9 percent increased the gross margin by approximately $20.1 million. The increase was offset by lower recoveries of fuel costs from Arkansas customers through that state s automatic fuel adjustment clause of approximately $5.9 million. In Arkansas, recovery of fuel costs is subject to a bandwidth mechanism. If fuel costs are within the bandwidth range, recoveries are not adjusted on a monthly basis; rather they are reset annually on April 1. Gross margin also was reduced by approximately $4.0 million due to milder weather. Lower recoveries under the Generation Efficiency Performance Rider (GEP Rider), which terminated in June 2002, decreased the gross margin by approximately $3.6 million in 2002. Additionally, lower levels of natural gas transportation cost that OG&E was allowed to recover from its customers as a result of the Acquisition Premium Credit Rider (APC Rider) and the Gas Transportation Adjustment Credit Rider (GTAC Rider) decreased the gross margin by approximately $2.1 million. See Note 18 of Notes to Consolidated Financial Statements for a further discussion of these riders. Although total expenditures from the January 2002 ice storm of approximately $92.0 million, which have been capitalized or deferred, did not impact operating results, the related loss of revenue due to interruption of service to our customers resulted in a decrease in the gross margin of approximately $1.5 million in 2002. Reduced amounts of off-system sales decreased the gross margin by approximately $1.1 million as off-system sales can vary based upon the supply and demand needs on OG&E s generation system.

Fuel expense decreased approximately $50.0 million or 10.3 percent in 2002 as compared to 2001 primarily due to an 11.1 percent decrease in the average cost of fuel per Kwh. In 2002, OG&E s fuel mix was 72 percent coal and 28 percent natural gas. Purchased power costs decreased approximately $20.7 million or 7.4 percent in 2002 as compared to 2001. This decrease was primarily due to approximately a 4.6 percent decrease in the volume of energy purchased and a 2.6 percent decrease in the cost of purchased energy per Kwh.

Other operating expenses decreased approximately $0.6 million or 0.1 percent in 2002 as compared to 2001. OG&E s operating and maintenance expense decreased approximately $4.4 million or 1.5 percent in 2002 as compared to 2001. This decrease was primarily due to a decrease of approximately $11.5 million in bad debt expense, a decrease of approximately $1.8 million in materials and supplies expense and a decrease of approximately $1.0 million in

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contract labor costs. Higher than normal bills driven by high natural gas prices early in 2001, along with customer cut-off moratoriums imposed during high temperature periods during the summer of 2001 contributed to significantly increased uncollectibles in 2001. The decrease in contract labor costs was due to higher contract labor costs incurred in 2001 due to the use of contractors to supplement OG&E s own crews to restore power after a major ice storm at the beginning of 2001 and a major wind storm in the early summer of 2001. The decreased operating and maintenance expenses were partially offset by an increase in employee pension and benefit costs of approximately $9.9 million. Pension expense increased primarily due to lower than forecasted returns on assets in the pension trust and the effect of lower discount rates used to measure the accumulated pension benefit obligation. The general upward trend in medical costs also contributed to the increase in employee benefit costs.

Depreciation expense increased approximately $3.3 million or 2.8 percent in 2002 as compared to 2001 due to a higher level of depreciable plant. Taxes other than income increased approximately $0.5 million or 1.1 percent in 2002 as compared to 2001 due to higher ad valorem taxes.

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Enogex Continuing Operations

(Dollars in millions)	**2003**	2002	2001
Operating revenues	**$ 2,327.8**	$ 1,684.0	$ 1,649.8
Gas and electricity purchased for resale	**2,019.1**	1,402.1	1,318.4
Natural gas purchases - other	**55.4**	70.5	142.9
Gross margin on revenues	**253.3**	211.4	188.5
Impairment of assets	**9.2**	48.3	---

Other operating expenses	**152.9**	166.1	154.1
Operating income (loss)	**$ 91.2**	$ (3.0)	$ 34.4
New well connects	**232**	166	279
Gathered volumes - MMBtu/d (A)	**1,012**	1,056	1,278
Incremental transportation volumes - MMBtu/d	**440**	486	427
Total throughput volumes - MMBtu/d	**1,452**	1,542	1,705
Natural gas processed - Mmcf/d (B)	**414**	455	641
Natural gas liquids produced (keep whole) - million gallons	**125**	197	314
Natural gas liquids produced (POL and fixed-fee) - million gallons	**134**	154	196
Total natural gas liquids produced - million gallons	**259**	351	510
Average sales price per gallon	**$ 0.595**	$ 0.406	$ 0.457
Natural gas marketed - Bbtu (C)	**374,296**	409,879	280,660
Average sales price per MMBtu	**$ 5.208**	$ 3.236	$ 4.403

(A) Million British thermal units per day.
(B) Million cubic feet per day.
(C) Billion British thermal units.
N/A - Not applicable.

2003 compared to 2002. Enogex s operating income in 2003 increased approximately $94.2 million as compared to 2002. The increase was primarily attributable to lower impairment charges and higher gross margins in all of Enogex s businesses, from among other things, improved management of pipeline system fuel, increased levels of firm transportation revenues, improved processing results and the negotiation of both new contracts and replacement contracts at better terms that resulted in increases in gathering fees and reductions in the purchase price of gas. Also contributing to Enogex s improvement were lower operating and maintenance expenses. Enogex sold its E&P business and its interest in Belvan during 2002 and Enogex sold its interest in NuStar during the first quarter of 2003; accordingly, these are reported as discontinued operations for the years ended December 31, 2003, 2002 and 2001 in the Consolidated Financial Statements. See Enogex Discontinued Operations below for a further discussion.

Transportation and storage contributed approximately $138.1 million of Enogex s gross margin in 2003 as compared to approximately $120.8 million in 2002, an increase of approximately $17.3 million or 14.3 percent. Gross margins benefited from increased storage revenues of approximately $8.8 million in 2003 as compared to 2002. The increased storage revenues were mainly due to new demand fees from the contract with OG&E related to the purchase of the Stuart Storage Facility in August 2002 and increased demand fees from both third parties and Enogex s marketing and trading business. Also contributing to the increase in gross margin was improved management of pipeline system fuel which, when coupled with higher natural gas prices, accelerated the authorized recovery of pipeline system fuel expense of approximately $10.5 million. The authorized recovery of pipeline system fuel was the result of

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Enogex under recovering fuel in prior periods. Also contributing to the increase in gross margin were increased levels of firm transportation revenues of approximately $5.5 million as a result of the Calpine Energy settlement and an increase in related demand fees recognized in 2003. These increases were partially offset by approximately a $4.1 million decrease in gross margin due to a revenue allocation related to bundled contracts from Enogex s transportation and storage business to Enogex s gathering and processing business to more accurately reflect the performance of our businesses, approximately $1.2 million higher electric compression costs and approximately a $1.1 million imbalance collectibility reserve.

Gathering and processing contributed approximately $91.3 million of Enogex s gross margin in 2003 as compared to approximately $73.0 million in 2002, an increase of approximately $18.3 million or 25.1 percent. Gathering gross margins increased approximately $9.8 million in 2003 as compared to 2002 primarily due to a $4.1 million revenue allocation related to bundled contracts from Enogex s transportation and storage business to Enogex s gathering and processing business to more accurately reflect the performance of our businesses and the negotiation of both new contracts and replacement contracts at better terms that resulted in increases in gathering fees and reductions in the purchase price of gas. Also, there was an increase in the number of well connects in 2003 as compared to 2002. Processing gross margins increased approximately $8.5 million in 2003 as compared to 2002. This increase was primarily due to wider commodity spreads between natural gas and natural gas liquids and better management and dispatch of the plants. However, processing volumes were lower as a result of economic dispatching of the network of processing plants based upon market conditions.

Marketing and trading contributed approximately $23.9 million of Enogex s gross margin in 2003 as compared to approximately $17.6 million in 2002, an increase of approximately $6.3 million or 35.8 percent. The increase was primarily due to Enogex recording a $9.0 million pre-tax loss as a cumulative effect of a change in accounting principle in the first quarter of 2003 rather than this loss being included in operating and maintenance expense. The cumulative effect of a change in accounting principle was the result of accounting for certain energy contracts and natural gas in storage at the lower of cost or market rather than on a mark-to-market basis. See Accounting Pronouncements below for a further discussion. This increase was partially offset by approximately a $2.2 million increase in demand fees paid to Enogex s transportation and storage business and approximately a $0.9 million increase related to the change in the timing of revenue recognition related to natural gas in storage under SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities, as amended, in 2003 as compared to mark-to-market accounting in 2002. This accounting change was driven by the rescission of mark-to-market accounting for natural gas in storage as a result of Emerging Issues Task Force (EITF) Issue No. 02-3, Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities , which was issued in October 2002. See Accounting Pronouncements below for a further discussion.

Other operating expenses, consisting of impairment charges, operating and maintenance expense, depreciation expense and taxes other than income, for Enogex were approximately $162.1 million in 2003 as compared to approximately $214.4 million in 2002, a decrease of approximately $52.3 million or 24.4 percent. Impairment charges were approximately $9.2 million in 2003 compared to approximately $48.3 million in 2002, a decrease of approximately

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$39.1 million or 81.0 percent. The impairment charges in 2003 related to certain idle Enogex natural gas compression assets. Operating and maintenance expenses were approximately $91.2 million in 2003 as compared to approximately $101.1 million in 2002, a decrease of approximately $9.9 million or 9.8 percent. The decrease was primarily due to lower uncollectibles expense of approximately $4.9 million, lower materials and supplies expense of approximately $4.2 million, lower expense allocations from the parent of approximately $1.6 million and lower miscellaneous operating expenses of approximately $1.4 million. These decreases were partially offset by higher outside service costs of approximately $2.0 million. Depreciation expense was approximately $44.2 million in 2003 as compared to approximately $49.3 million in 2002, a decrease of approximately $5.1 million or 10.3 percent. The decrease was primarily the result of ceasing depreciation on the assets written down as of December 31, 2002 due to the Company s decision to sell these assets and classify them as held for sale in the fourth quarter of 2002. Taxes other than income were approximately $17.5 million in 2003 as compared to approximately $15.7 million in 2002, an increase of approximately $1.8 million or 11.5 percent. The increase was the result of higher ad valorem taxes.

2002 compared to 2001. Enogex s operating income in 2002 decreased approximately $37.4 million or 108.7 percent as compared to 2001. The decrease was primarily attributable to impairment losses in the fourth quarter of 2002 related to natural gas processing plants and compression assets, which Enogex determined were no longer needed in its business. Absent the impairment charges, Enogex s operating income for 2002 would have been approximately $10.9 million higher than in 2001 primarily due to improved gross margins in Enogex s transportation and storage business and marketing and trading business, which were only partially offset by increased operating and maintenance expenses and decreased gross margins in Enogex s gathering and processing business. Enogex sold its E&P business and its interest in Belvan during 2002 and Enogex sold its interest in NuStar during the first quarter of 2003; accordingly, these are reported as discontinued operations for the years ended December 31, 2003, 2002 and 2001 in the Consolidated Financial Statements. See Enogex Discontinued Operations below for a further discussion.

Transportation and storage contributed approximately $120.8 million of Enogex s gross margin in 2002 as compared to approximately $95.1 million in 2001, an increase of approximately $25.7 million or 27.0 percent. Gross margins benefited from increased fuel recoveries of prior under recovered fuel of approximately $10.8 million as compared to 2001, increased firm transportation revenue, primarily the result of new transportation contracts to merchant electric generation, of approximately $6.1 million as compared to 2001, higher volumes and prices on interruptible transmission service of approximately $3.8 million as compared to 2001, increased firm and interruptible transportation on Ozark of approximately $3.3 million as compared to 2001 and increased storage revenues of approximately $1.4 million as compared to 2001.

Gathering and processing contributed approximately $73.0 million of Enogex s gross margin in 2002 as compared to approximately $82.8 million in 2001, a decrease of approximately $9.8 million or 11.8 percent. Gathering gross margins decreased approximately $3.9 million in 2002 as compared to 2001 primarily due to a decrease in gathered volumes as a result of the decrease in the number of well connects in 2002 as compared to 2001. Processing gross margins decreased approximately $5.9 million in 2002 as compared to 2001 primarily due

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to a decrease in processed volumes which were adversely affected by the January 2002 ice storm, which Enogex estimates caused processed volumes to be approximately 10.7 million gallons less.

Marketing and trading contributed approximately $17.6 million of Enogex s gross margin in 2002 as compared to approximately $10.6 million in 2001, an increase of approximately $7.0 million or 66.0 percent. Gross margins benefited from approximately a $7.6 million increase in mark-to-market gains on storage contracts that were substantially realized during the first quarter of 2003, increased natural gas sales margins of approximately $6.1 million and increased income from other financial instruments of approximately $0.7 million partially offset by approximately a $3.5 million increase in demand fees paid to Enogex s transportation and storage business, approximately a $2.2 million decrease in third party gas storage management revenues and approximately a $1.7 million decrease in the power sales gross margin.

Other operating expenses for Enogex were approximately $214.4 million in 2002 as compared to approximately $154.1 million in 2001, an increase of approximately $60.3 million or 39.1 percent. There were impairment charges of approximately $48.3 million in 2002 related to the disposition of natural gas processing plants and compression assets that were no longer needed in Enogex s business. Operating and maintenance expenses were approximately $101.1 million in 2002 as compared to approximately $93.0 million in 2001, an increase of approximately $8.1 million or 8.7 percent. The primary causes for the increase were approximately $3.4 million of increased overhead allocations from the Company, $3.3 million in uncollectible accounts as a result of the bankruptcy of a large customer, increased employee benefit costs of approximately $3.1 million and increased building rentals of approximately $2.1 million partially offset by lower consultant fees for outside services of approximately $1.5 million, lower payroll expenses of approximately $1.5 million and approximately a $0.9 million decrease in property insurance. Depreciation expense was approximately $49.3 million in 2002 as compared to approximately $45.3 million in 2001, an increase of approximately $4.0 million or 8.8 percent. The increase was primarily the result of a higher level of depreciable plant.

Consolidated Other Income and Expense, Interest Expense and Income Tax Expense

2003 compared to 2002. Other income includes, among other things, contract work performed by OG&E, non-operating rental income, gain on the sale of assets, profit on the retirement of fixed assets, minority interest income and miscellaneous non-operating income. Other income was approximately $8.1 million in 2003 as compared to approximately $3.7 million in 2002, an increase of approximately $4.4 million. The increase was primarily due to a pre-tax gain of approximately $5.3 million related to the sale of approximately 29 miles of transmission lines of the Ozark pipeline in January 2003 partially offset by approximately a $0.9 million decrease in other income due to a decrease in the asset associated with the deferred compensation plan.

Other expense includes, among other things, expenses from loss on the sale of assets, loss on retirement of fixed assets, minority interest expense, miscellaneous charitable donations, expenditures for certain civic, political and related activities and miscellaneous deductions. Other expense was approximately $9.0 million in 2003 as compared to approximately $4.7 million in 2002, an increase of approximately $4.3 million. This increase was primarily due to

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an increase of approximately $1.1 million in minority interest expense related to the gain from the sale of approximately 29 miles of transmission lines of the Ozark pipeline in January 2003 that was attributable to the minority interest. Also contributing to the increase was approximately a $1.0 million increase in the liability associated with the deferred compensation plan, a $0.9 million loss on the retirement of fixed assets, a $0.7 million loss from the dissolution of a lease in the third quarter of 2003 and a $0.1 million increase due to the sale of the Company s aircraft in the third quarter of 2003.

Net interest expense includes interest income, interest expense and other interest charges. Net interest expense was approximately $96.7 million in 2003 as compared to approximately $109.1 million in 2002, a decrease of approximately $12.4 million or 11.4 percent. This decrease was primarily due to a reduction in interest expense of approximately $7.9 million related to the retirement of $140.0 million of Enogex debt during 2002, a $2.5 million decrease in interest expense due to a lower average commercial paper balance in 2003 as compared to 2002 and a $2.3 million decrease related to lower interest rates on outstanding debt achieved from entering into interest rate swap agreements.

Income tax expense was approximately $73.7 million in 2003 as compared to approximately $44.6 million in 2002, an increase of approximately $29.1 million or 65.2 percent. The increase was primarily due to higher pre-tax income for Enogex partially offset by lower pre-tax income for OG&E. In addition, there was a greater deduction for the Company s Employee Stock Ownership Plan dividends in 2003, which reduced taxable income as compared to 2002, a reversal of previously accrued federal income tax in 2002 related to several issues that were resolved in favor of the Company and an Oklahoma income tax refund in 2002 related to Oklahoma investment tax credits from prior years.

2002 compared to 2001. Other income was approximately $3.7 million in 2002 as compared to approximately $3.1 million in 2001, an increase of approximately $0.6 million or 19.4 percent. This increase was primarily due to a reduction of approximately $1.4 million in the liability associated with the deferred compensation plan and approximately a $0.4 million increase related to a gain on the sale of assets. These increases were partially offset by a decrease in minority interest income of approximately $0.8 million and approximately a $0.3 million decrease in non-operating rental income.

Other expense was approximately $4.7 million in 2002 as compared to approximately $4.2 million in 2001, an increase of approximately $0.5 million or 11.9 percent. This increase was primarily due to approximately a $0.6 million loss on the value of plan assets of the deferred compensation plan and approximately a $0.4 million loss on the sale of inventory partially offset by approximately a $0.2 million decrease in miscellaneous charitable donations and a decrease of approximately $0.2 million in expenditures for certain civic, political and related activities.

Net interest expense was approximately $109.1 million in 2002 as compared to approximately $123.0 million in 2001, a decrease of approximately $13.9 million or 11.3 percent. This decrease was primarily due to a reduction in interest expense of approximately $6.8 million related to lower interest rates on outstanding debt achieved from entering into interest rate swap agreements, approximately a $3.9 million decrease in interest expense related

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to the retirement of $140.0 million of Enogex debt during 2002 and approximately a $4.5 million decrease in interest expense related to commercial paper activity. These decreases were partially offset by approximately a $0.6 million increase in interest expense due to an increase in commercial paper service fees.

Income tax expense was approximately $44.6 million in 2002 as compared to approximately $52.9 million in 2001, a decrease of approximately $8.3 million or 15.7 percent. This decrease was primarily due to a higher pre-tax loss at Enogex in 2002. In addition, there was a reversal of previously accrued federal income tax in 2002 related to several issues that were resolved in favor of the Company and an Oklahoma income tax refund in 2002 related to Oklahoma investment tax credits from prior years which lowered the effective tax rate from 34.3 percent in 2001 to 32.2 percent in 2002.

Enogex Discontinued Operations

On March 25, 2002, Enogex entered into an Agreement of Sale and Purchase with West Texas Gas, Inc. to sell all of its interests in Belvan for approximately $9.8 million. The effective date of the sale was January 1, 2002 and the closing occurred on March 28, 2002. The Company recognized approximately a $1.6 million after tax gain related to the sale of these assets.

On August 5, 2002, Enogex entered into an Agreement of Sale and Purchase with Chesapeake Exploration Limited Partnership to sell all of its exploration and production assets located in Oklahoma, Texas, Arkansas and Mississippi for approximately $15.0 million. The effective date of the sale was July 1, 2002 and the closing occurred on September 19, 2002. The Company recognized approximately a $2.3 million after tax loss related to the sale of these assets.

On November 14, 2002, Enogex entered into an Agreement of Sale and Purchase with Quicksilver Resources, Inc. to sell all of its exploration and production assets located in Michigan for approximately $32.0 million. The effective date of the sale was July 1, 2002 and the closing occurred on December 2, 2002. The Company recognized approximately a $2.9 million after tax gain related to the sale of these assets.

During the third quarter of 2002, the Company decided to sell all of its interests in NuStar. On January 23, 2003, Enogex entered into an Agreement of Sale and Purchase with Benedum Gas Partners, L.P. to sell all of the interests of its subsidiary, Enogex Products Corporation, in the west Texas properties consisting of NuStar, which has operations consisting of the extraction and sale of natural gas liquids, for approximately $37.0 million. The effective date of the sale was January 1, 2003 and the closing occurred on February 18, 2003. The Company recognized approximately a $1.4 million after tax gain related to the sale of these assets in the first quarter of 2003. The final accounting for the NuStar sale was completed in the third quarter of 2003 which resulted in an additional charge of approximately $0.2 million after tax which was recorded in the third quarter of 2003. The final accounting is subject to approval by all parties to the sale of the joint venture interest.

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As a result of these sale transactions, Enogex s E&P business, its interest in NuStar and its interest in Belvan, all of which were part of the Natural Gas Pipeline segment, have been reported as discontinued operations for the years ended December 31, 2003, 2002 and 2001 in the Consolidated Financial Statements. Results for these discontinued operations are summarized and discussed below.

(In millions)	**2003**	2002	2001
Operating revenues	**$ 7.8**	$ 79.5	$ 121.4
Gas purchased for resale	**5.9**	49.5	81.0
Natural gas purchases - other	**0.6**	6.4	2.7
Gross margin on revenues	**1.3**	23.6	37.7
Other operating expenses	**1.4**	17.1	30.6

Operating income (loss)	**$ (0.1)**	$ 6.5	$ 7.1

2003 compared to 2002. Gross margin decreased approximately $22.3 million or 94.5 percent in 2003 as compared to 2002. Other operating expenses decreased approximately $15.7 million or 91.8 percent in 2003 as compared to 2002. The decreases in the gross margin and other operating expenses were attributable to the sale of Enogex s E&P business and Belvan during 2002 and the sale of NuStar in February 2003.

2002 compared to 2001. Gross margin decreased approximately $14.1 million or 37.4 percent in 2002 as compared to 2001. The decrease was primarily attributable to approximately a $10.0 million decrease in natural gas sales due to lower prices and sales volumes in 2002 as compared to 2001 for Enogex s E&P business, approximately a $3.9 million decrease in natural gas and natural gas liquids sales related to lower prices and sales volumes related to NuStar and Belvan and approximately a $0.2 million decrease in crude oil sales.

Other operating expenses decreased approximately $13.5 million or 44.1 percent in 2002 as compared to 2001. Other operating expenses include operating and maintenance expenses, depreciation expense and taxes other than income. Operating and maintenance expenses decreased approximately $3.6 million or 21.9 percent in 2002 as compared to 2001. This decrease was due to approximately a $2.9 million decrease in Enogex s E&P business expenses as these assets were sold in 2002 and approximately a $0.7 million decrease in miscellaneous operating expenses related to NuStar and Belvan as these assets have been or were in the process of being sold in 2002.

Depreciation expense decreased approximately $9.9 million or 68.8 percent in 2002 as compared to 2001. This decrease was primarily due to approximately a $6.0 million impairment charge in 2001 related to Belvan and approximately a $3.9 million decrease due to ceasing depreciation on the assets, which have been or were in the process of being sold.

Financial Condition

The balance of Cash and Cash Equivalents was approximately $245.6 million and $44.4 million at December 31, 2003 and 2002, respectively, an increase of approximately $201.2 million. The increase was primarily due to an increase in short-term investments at December 31, 2003 in anticipation of the completion of the McClain Plant acquisition. Due to a delay in

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the completion of the McClain Plant acquisition, in January 2004, the Company used short-term investments to reduce the commercial paper balance to approximately $30.5 million at January 31, 2004.

The balance of Accounts Receivable, Net was approximately $350.2 million and $304.6 million at December 31, 2003 and 2002, respectively, an increase of approximately $45.6 million or 15.0 percent. The increase was primarily due to an increase in OG&E s fuel costs in 2003 as compared to 2002, higher natural gas prices associated with Enogex s activities in the fourth quarter of 2003 and increased usage due to customer growth in OG&E s service territory, which increases were only partially offset by the rate reduction ordered for OG&E that went into effect on January 6, 2003, weaker weather-related demand and lower volumes associated with Enogex s activities in the fourth quarter of 2003.

The balance of Accrued Unbilled Revenues was approximately $38.0 million and $28.2 million at December 31, 2003 and 2002, respectively, an increase of approximately $9.8 million or 34.8 percent. Accrued unbilled revenues represent the 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 usages and prices during the period. The increase was primarily due to an increase in OG&E s fuel costs in 2003 as compared to 2002 and increased usage due to customer growth in OG&E s service territory partially offset by weaker weather-related demand.

The balance of Fuel Inventories was approximately $163.3 million and $99.7 million at December 31, 2003 and 2002, respectively, an increase of approximately $63.6 million or 63.8 percent. The increase was due to more gas volumes injected into storage at higher prices during December 2003 as compared to December 2002. Effective December 31, 2003, approximately $20.8 million of natural gas storage inventory that was previously classified as Property, Plant and Equipment used in Enogex Inc. s business activities was reclassified to Fuel Inventories on the Consolidated Balance Sheet. During the fourth quarter of 2003, Enogex implemented a business process to actively manage seasonal opportunities around the four billion cubic feet previously reserved to manage pipeline system requirements during peak periods. The intent of management is to capture commercial opportunities while maintaining adequate inventory levels necessary to meet ongoing contractual obligations.

The balance of current Price Risk Management assets was approximately $61.3 million and $17.1 million at December 31, 2003 and 2002, respectively, an increase of approximately $44.2 million. The increase was due to significant volatility and higher natural gas prices associated with OGE Energy Resources, Inc. s (OERI) trading activities during 2003. This increase is partially offset by an increase in current Price Risk Management liabilities.

The balance of the Gas Imbalance assets was approximately $70.0 million and $47.8 million at December 31, 2003 and 2002, respectively, an increase of approximately $22.2 million or 46.4 percent. The Gas Imbalance asset is comprised of planned or managed imbalances related to Enogex s marketing and trading business, referred to as park and loan transactions, and pipeline imbalances, which are operational imbalances. Park and loan transactions were approximately $45.4 million and $31.1 million at December 31, 2003 and 2002, respectively, an

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increase of approximately $14.3 million. The increase was due to the Company parking more gas on third party pipeline systems at December 31, 2003 as compared to December 31, 2002. The Company expects to obtain and sell the majority of this gas during the first quarter of 2004 and to reduce the operational imbalance during 2004. Operational imbalances were approximately $24.6 million and $16.7 million at December 31, 2003 and 2002, respectively, an increase of approximately $7.9 million or 47.3 percent. The increase was due to higher natural gas prices and volumes.

The balance of Fuel Clause Over Recoveries (net of Fuel Clause Under Recoveries) was approximately $28.4 million at December 31, 2003. The balance of Fuel Clause Under Recoveries was approximately $14.7 million at December 31, 2002. The increase in fuel clause over recoveries was due to over recoveries from OG&E s customers as the amount billed during 2003 exceeded OG&E s cost of fuel. The cost of fuel subject to recovery through the fuel clause mechanism was approximately $1.21 per MMBtu in December 2003, and was approximately $1.54 per MMBtu in December 2002. OG&E s fuel recovery clauses are designed to smooth the impact of fuel price volatility on customers bills. As a result, OG&E under recovers fuel cost in periods of rising prices above the baseline charge for fuel and over recovers fuel cost when prices decline below the baseline charge for fuel. Provisions in the fuel clauses allow OG&E to amortize under or over recovery. OG&E began amortizing the under collected amounts for 2002 beginning with the April 2003 customers bills.

The balance of Prepaid Benefit Obligation was approximately $55.7 million and $44.9 million at December 31, 2003 and 2002, respectively, an increase of approximately $10.8 million or 24.1 percent. The increase was due to the pension plan funding during the third quarter of 2003 partially offset by a decrease due to pension accruals being credited to the prepaid benefit obligation.

The balance of Short-Term Debt was approximately $202.5 million and $275.0 million at December 31, 2003 and 2002, respectively, a decrease of approximately $72.5 million or 26.4 percent. The decrease was primarily due to proceeds received from the sale of the Company s common stock in the third quarter of 2003, the sale of the Company aircraft in the third quarter of 2003, the sale of Ozark and NuStar and from the sale of natural gas inventory by Enogex during the first quarter of 2003 and an income tax refund received in the fourth quarter of 2003, which were used to reduce the commercial paper balance at the holding company. Due to a delay in the completion of the McClain Plant acquisition, in January 2004, the Company used short-term investments to reduce the commercial paper balance to approximately $30.5 million at January 31, 2004.

The balance of current Price Risk Management liabilities was approximately $46.9 million and $13.9 million at December 31, 2003 and 2002, respectively, an increase of approximately $33.0 million. The increase was due to significant volatility and higher natural gas prices associated with OERI s trading activities during 2003. This increase was offset by an increase in current Price Risk Management assets.

The balance of Accrued Pension and Benefit Obligations was approximately $167.4 million and $184.2 million at December 31, 2003 and 2002, respectively, a decrease of

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approximately $16.8 million or 9.1 percent. The decrease was primarily due to a decrease in the liability associated with the Company s pension plan. See Note 15 of Notes to Consolidated Financial Statements for a further discussion.

Off-Balance Sheet Arrangements

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

Heat Pump Loans

OG&E has a heat pump loan program, whereby, qualifying customers may obtain a loan from OG&E to purchase a heat pump. Customer loans are available for a minimum of $1,500 to a maximum of $13,000 with a term of six months to 84 months. The finance rate is based upon market rates and is reviewed and updated periodically. The interest rates were 11.55 percent and 10.99 percent at December 31, 2003 and 2002, respectively.

OG&E sold approximately $8.5 million, $12.7 million and $25.0 million of its heat pump loans in December 2002, November 1999 and October 1998, respectively, as part of separate securitization transactions through OGE Consumer Loan 2002, LLC, OGE Consumer Loan II LLC and OGE Consumer Loan LLC, respectively. The following table contains information related to each securitization.

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	2002	1999	1998
Date heat pump loans sold	December 2002	November 1999	October 1998
Total amount of heat pump loans sold (in millions)	$ 8.5	$ 12.7	$ 25.0
Heat pump loan balance at December 31, 2003 (in millions)	$ 5.9	$ 2.1	$ 0.4
Note interest rate	5.25%	8.00%	6.75%
Base servicing fee rate (paid monthly)	0.375%	0.375%	0.375%
Trustee/custodian fees (paid quarterly) (in whole dollars)	$ 1,250	$ 1,250	$ 1,250
Owner trustee fees (paid annually) (in whole dollars)	$ 4,000	$ 4,000	$ 4,000
Sole director s fee (paid quarterly) (in whole dollars)	$ 1,125	$ 625	$ 625
Loss exposure by securitization issue (in millions)	$ 0.8	$ 0.3	$ ---

OG&E Railcar Leases

At December 31, 2003, OG&E has noncancellable operating leases which have purchase options covering 1,479 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. At the end of the lease term which is March 31, 2006, OG&E has the option to purchase the railcars at a stipulated fair market value. If OG&E chooses not to purchase the railcars, OG&E has a loss exposure up to approximately $9.0 million related to the fair market value of the railcars to the extent the fair market value is less than 80 percent of the lessor s cost of equipment. 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.

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Liquidity and Capital Requirements

The Company s primary needs for capital are related to replacing or expanding existing facilities in OG&E s electric utility business and replacing or expanding existing facilities at Enogex. Other capital requirements are primarily related to maturing debt, operating lease obligations, hedging activities, natural gas storage and delays in recovering unconditional fuel purchase obligations. The Company generally meets its cash needs through a combination of internally generated funds, short-term borrowings 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 - 5years	More than 5 years
OG&E capital expenditures including AFUDC	$ 775.0	$ 365.0(A)	$ 410.0	N/A	N/A
Enogex capital expenditures and acquisitions	96.4	34.2	62.2	N/A	N/A
Other Operations capital expenditures	21.0	7.0	14.0	N/A	N/A
Total capital expenditures	892.4	406.2	486.2	N/A	N/A
Maturities of long-term debt	1,489.4	53.1	148.6	$ 8.4	$ 1,279.3
Pension funding obligations	56.0	56.0	N/A	N/A	N/A

Total capital requirements	2,437.8	515.3	634.8	8.4	1,279.3
Operating lease obligations					
OG&E railcars	57.6	5.4	10.9	10.9	30.4
Enogex noncancellable operating leases	12.4	3.6	6.3	2.3	0.2
Total operating lease obligations	70.0	9.0	17.2	13.2	30.6
Other purchase obligations and commitments					
OG&E cogeneration capacity payments	414.9	152.8	174.3	87.8	N/A
OG&E fuel minimum purchase commitments	942.0	160.8	320.9	307.9	152.4
Other	81.0	5.0	11.2	14.9	49.9
Total other purchase obligations and commitments	1,437.9	318.6	506.4	410.6	202.3
Total capital requirements, operating lease obligations and other purchase obligations and commitments	3,945.7	842.9	1,158.4	432.2	1,512.2
Amounts recoverable through automatic fuel adjustment clause (B)	(1,419.5)	(324.0)	(506.1)	(406.6)	(182.8)
Total, net	$ 2,526.2	$ 518.9	$ 652.3	$ 25.6	$ 1,329.4

(A) Includes approximately $165 million related to the acquisition of the McClain Plant.

(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 applicable

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,

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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 further discussion.

2003 Capital Requirements and Financing Activities

Total capital requirements, consisting of capital expenditures, maturities and retirements of long-term debt and pension funding obligations, were approximately $262.3 million and contractual obligations, net of recoveries through automatic fuel adjustment clauses, were approximately $6.4 million resulting in total net capital requirements and contractual obligations of approximately $268.7 million in 2003. Approximately $6.4 million of the 2003 capital requirements were to comply with environmental regulations. This compares to net capital requirements of approximately $423.3 million and net contractual obligations of approximately $6.7 million totaling approximately $430.0 million in 2002, of which approximately $2.8 million was to comply with environmental regulations. Approximately $86.6 million of capital expenditures in 2002 were associated with the costs of the January 2002 ice storm, which severely damaged OG&E s electric transmission and distribution systems. Excluding the ice storm, total net capital requirements would have been approximately $336.7 million. During 2003, the Company s sources of capital were internally generated funds from operating cash flows, short-term borrowings, proceeds from the sale of assets, the Company s equity issuance in the third quarter and the issuance of common stock pursuant to the DRIP. The Company s short-term borrowings consist primarily of commercial paper and short-term bank loans. 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. The cash and cash equivalents balance at December 31, 2003 significantly increased from December 31, 2002 due to the planned acquisition of the McClain Plant, which has been delayed. Due to the delay in the completion of the McClain Plant acquisition, in January 2004, the Company used short-term investments to reduce the commercial paper balance to approximately $30.5 million at January 31, 2004. Changes in working capital reflect the seasonal nature of the Company s business, the revenue lag between billing and collection for customers and fuel inventories. In 2002, OGE Energy Corp. commercial paper was used to fund expenditures associated with the ice storm.

Long-Term Debt

During 2003 and 2002, approximately $19.0 million and $113.0 million, respectively, of Enogex s long-term debt matured and approximately $12.0 million and $27.0 million, respectively, was redeemed during 2003 and 2002 which is itemized in the following table.

(In millions)	**2003**	2002
Series Due 2002 -- 7.02% - 8.13%	**$ ---**	$ 113.0
Series Due 2003 -- 6.60% - 8.28%	**19.0**	---
Series Due 2012 -- 8.35% - 8.90%	**---**	10.0
Series Due 2017 -- 8.96%	**---**	15.0
Series Due 2018 -- 7.15%	**2.0**	2.0
Series Due 2023 -- 7.75%	**10.0**	---
Total	**$ 31.0**	$ 140.0

Interest Rate Swap Agreements

At December 31, 2003 and 2002, the Company had three outstanding interest rate swap agreements: (i) OG&E entered into an interest rate swap agreement, effective March 30, 2001, to convert $110.0 million of 7.30 percent fixed rate debt due October 15, 2025, to a variable rate based on the three month London InterBank Offering Rate (LIBOR) and (ii) Enogex entered into two separate interest rate swap agreements, effective July 15, 2002 and October 24, 2002, to convert $100.0 million of 8.125 percent fixed rate debt due January 15, 2010, to a variable rate based on the six month LIBOR. The objective of these interest rate swaps was to achieve a lower cost of debt and to raise the percentage of total corporate long-term floating rate debt to reflect a level more in line with industry standards. These interest rate swaps qualified as fair value hedges under SFAS No. 133 and met all of the requirements for a determination that there was no ineffective portion as allowed by the shortcut method under SFAS No. 133.

At December 31, 2003 and 2002, the fair values pursuant to the interest rate swaps were approximately $7.6 million and $15.9 million, respectively, and are classified as Deferred Charges and Other Assets Price Risk Management in the accompanying Consolidated Balance Sheets. A corresponding net increase of approximately $7.6 million and $15.9 million was reflected in Long-Term Debt at December 31, 2003 and 2002, respectively, as these fair value hedges were effective at December 31, 2003 and 2002.

On April 6, 2001, the Company entered into a one-year interest rate swap agreement to lock in a fixed rate of 4.41 percent, effective April 10, 2001, on $140.0 million of variable rate short-term debt. The objective of this interest rate swap was to achieve a lower cost of debt and to reduce exposure to short-term interest rate volatility associated with the Company s commercial paper program. This interest rate swap initially qualified for hedge accounting treatment as a cash flow hedge under SFAS No. 133. However, due to unexpected changes in the level of commercial paper issued during the third quarter of 2001, hedge accounting treatment under SFAS No. 133 was discontinued as of July 1, 2001, and all subsequent changes in the fair value of the swap were recorded as Interest Expense. During 2002 and 2001, approximately $0.2 million and $1.3 million, respectively, were recorded as Interest Expense in the accompanying Consolidated Statements of Income. At December 31, 2002, no amounts were included in Accumulated Other Comprehensive Loss related to this cash flow hedge. As of

December 31, 2001, approximately a $0.1 million after tax loss was included in Accumulated Other Comprehensive Loss related to this cash flow hedge.

Future Capital Requirements

Capital Expenditures

The Company s current 2004 to 2006 construction program includes the purchase of New Generation as discussed below. OG&E currently has QF contracts for the purchase of 540 MWs, all of which expire in the next one to five years. The Company will continue reviewing all of the supply alternatives to replace expiring QF contracts that minimize the total cost of generation to our customers. Accordingly, OG&E will continue to explore opportunities to build or buy power plants in order to serve its native load. As a result of the high volatility of current natural gas prices and the increase in natural gas prices, OG&E will also assess the feasibility of constructing additional base load coal-fired units. See Note 18 of Notes to Consolidated Financial Statements for a description of current proceedings involving a PowerSmith QF contract.

On August 18, 2003, OG&E signed an asset purchase agreement to acquire NRG McClain LLC s 77 percent interest in the 520 MW McClain Plant. Closing has been delayed pending receipt of FERC approval. The purchase price for the interest in the McClain Plant is approximately $159.9 million, subject to adjustment for prepaid gas and property taxes. See Overview Pending Acquisition of Power Plant. If approval is received, funding for the acquisition is to be provided by proceeds received by the Company from its equity offering in the third quarter of 2003, and a debt issuance by OG&E. To reliably meet the increased electricity needs of OG&E s customers during the foreseeable future, OG&E will continue to invest to maintain the integrity of the delivery system. Approximately $10.5 million of the Company s capital expenditures budgeted for 2004 are to comply with environmental laws and regulations.

Pension and Postretirement Benefit Plans

During 2003, actual asset returns for the Company s defined benefit pension plan were positively affected by growth in the equity markets. Approximately 61 percent of the pension plan assets are invested in listed common stocks with the balance invested in corporate debt and U.S. Government securities. For the year ended December 31, 2003, asset returns on the pension plan were approximately 22.76 percent. 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 $48.8 million in 2002 to approximately $50.0 million in 2003. This increase was necessitated by the lower investment returns on assets and lower discount rates used to value the accumulated pension benefit obligations. During 2004, the Company plans to contribute approximately $56.0 million to the pension plan. The level of funding is dependent on returns on plan assets and future discount rates. Higher returns on plan assets and increases in discount rates will reduce funding requirements to the plan. The following table indicates the sensitivity of the pension plans funded status to these variables.

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	Change	Impact on Funded Status
Actual plan asset returns	+/- 5 percent	+/- $13.9 million
Discount rate	+/- 0.25 percent	+/- $16.3 million
Contributions	+ $10.0 million	+ $10.0 million
Expected long-term return on plan assets	+/- 1 percent	None

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.

During 2003 and 2002, the Company made contributions to the pension plan that exceeded amounts previously recognized as net periodic pension expense and recorded a prepaid benefit obligation at December 31, 2003 and 2002 of approximately $55.7 million and $44.9 million, respectively. At December 31, 2003 and 2002, the Company s projected pension benefit obligation exceeded the fair value of pension plan assets by approximately $131.8 million and $156.7 million, respectively. As a result of recording a prepaid benefit obligation and having a funded status where the projected benefit obligations exceeded the fair value of plan assets, provisions of SFAS No. 87, Employers Accounting for Pensions , required the recognition of an additional minimum liability in the amount of approximately $137.6 million and $163.9 million, respectively, at December 31, 2003 and 2002. 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 2003 or 2002 and did not require a usage of cash and is therefore excluded from the accompanying Consolidated Statements of Cash Flows. The amount recorded as an intangible asset equaled the unrecognized prior service cost with the remainder recorded in Accumulated Other Comprehensive Income. The amount in Accumulated Other Comprehensive Income represents a net periodic pension cost to be recognized in the Consolidated Statements of Income in future periods.

Security Ratings

On October 31, 2002, Fitch Ratings (Fitch) reaffirmed the ratings of OGE Energy Corp. s senior unsecured debt at A and short-term debt at F1, OG&E s senior unsecured debt at AA- and short-term debt at F1 and Enogex s senior unsecured debt at BBB. The rating outlook is stable. Fitch cited the solid financial position, low business risk and strong cash flows at OG&E and the higher risk nature of Enogex acknowledging that renewed management focus on cost reductions and reducing cash flow volatility across all unregulated business lines should allow for gradual strengthening of Enogex s credit profile.

On January 15, 2003, Standard & Poor s Ratings Services (Standard & Poor s) lowered the credit ratings of OGE Energy Corp. s senior unsecured debt from A- to BBB. Standard &

Poor s also lowered the credit ratings of OG&E s and Enogex s senior unsecured debt from A- to BBB+. OGE Energy Corp. s short-term commercial paper ratings were affirmed at A-2. The outlook is now stable. Standard & Poor s cited the relatively low-risk low-cost efficient operations of OG&E and the business and financial profile of Enogex, which has higher risk. Standard & Poor s further cited the rationalization at Enogex has resulted in a business-risk reduction, but it is not adequate to warrant an improvement in the overall business score. The Company may experience somewhat higher borrowing costs but does not expect the actions by Standard & Poor s to have a significant impact on the Company s consolidated financial position, liquidity or results of operations.

On February 5, 2003, Moody s Investors Service (Moody s) lowered the credit ratings of OGE Energy Corp. s senior unsecured debt to Baa1 from A3, OG&E s senior unsecured debt to A2 from A1 and Enogex s senior unsecured debt to Baa3 from Baa2. OGE Energy Corp. s short-term commercial paper rating was unchanged at P-2. The outlook for OGE Energy Corp. and OG&E is stable and Enogex is negative. Moody s cited the diminished credit profile of both OG&E and Enogex with OG&E having competitive generation and stable cash flow but with regulatory risk associated with the acquisition of at least 400 MWs of New Generation and Enogex exposed to the seasonality of its gas processing business although it has reduced its keep whole exposure. The Company may experience somewhat higher borrowing costs but does not expect the actions by Moody s to have a significant impact on the Company s consolidated financial position, liquidity or results of operations. As a result of Enogex s rating being lowered to Baa3, OGE Energy Corp. was required to issue a $5.0 million guarantee on OERI s behalf for a counterparty. In December 2003, this guarantee was increased to $7.0 million. At December 31, 2003, there is approximately a $1.9 million outstanding liability balance related to this guarantee. In the event one or more of the credit ratings were to fall below investment grade, Enogex may seek OGE Energy Corp. guarantees to satisfy its customers in order to avoid disruption of its marketing and trading business.

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, 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, funds received from the 2003 equity offering, proceeds from the sales of common stock pursuant to the DRIP and short-term debt will be adequate over the next three years to meet other anticipated capital expenditures, operating needs, payment of dividends and maturities of long-term debt. As discussed below, the Company utilizes short-term debt to satisfy temporary working capital needs and as an interim source of financing capital expenditures until permanent financing is arranged. The Company

issued equity in the third quarter of 2003 and issued common stock pursuant to the DRIP during 2003. Later in 2004, assuming the acquisition of the McClain Plant is approved by the FERC, OG&E plans to issue debt to fund the purchase of the McClain Plant and for general corporate purposes and the Company plans to issue common stock pursuant to the DRIP during 2004.

Short-Term Debt

Short-term borrowings generally are used to meet working capital requirements. The following table shows the Company s lines of credit in place and available cash at January 31, 2004. Short-term borrowings are expected to consist of a combination of bank borrowings and commercial paper.

Lines of Credit and Available Cash *(In millions)*

Entity	Amount Available	Amount Outstanding	Maturity
OGE Energy Corp. (A)	$ 15.0	$ ---	April 6, 2004

OG&E	100.0	---	June 26, 2004
OGE Energy Corp. (A)	300.0	---	December 9, 2004
Total	415.0	---	
Cash	31.0	N/A	N/A
Total	$ 446.0	$ ---	

(A) The lines of credit at OGE Energy Corp. are used to back up the Company s commercial paper borrowings, which were approximately $30.5 million at January 31, 2004. As shown in the table above, on December 11, 2003, the Company renewed its credit facility of $300.0 million maturing on December 9, 2004. This agreement has a one-year term.

The Company s ability to access the commercial paper market could be adversely impacted by a commercial paper ratings downgrade. The lines of credit contain rating grids that require annual fees and borrowing rates to increase if the Company suffers an adverse ratings impact. The impact of additional downgrades of the Company s rating would result in an increase in the cost of short-term borrowings of approximately five to 20 basis points, but would not result in any defaults or accelerations as a result of the rating changes. See Future Capital Requirements for potential financing needs upon a downgrade by Moody s of Enogex s long-term debt rating.

Unlike the Company and Enogex, OG&E must obtain regulatory approval from the FERC in order to borrow on a short-term basis. OG&E has the necessary regulatory approvals to incur up to $400 million in short-term borrowings at any one time.

Asset Sales

Also contributing to the liquidity of the Company have been numerous asset sales by Enogex. Since January 1, 2002, completed sales generated net proceeds of approximately $101.3 million. Sales proceeds generated to date have been used to reduce debt at Enogex and commercial paper at the holding company.

The Company continues to evaluate opportunities to enhance shareowner returns and achieve long-term financial objectives through acquisitions of assets that may

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complement its existing portfolio. Permanent financing would be required for any such acquisitions.

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 liabilities at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the reporting period. Changes to these assumptions and estimates could have a material effect on the Company s Consolidated Financial Statements particularly as they relate to pension expense and impairment estimates. However, the Company believes it has taken reasonable but conservative positions, where assumptions and estimates are used, in order to minimize the negative financial impact to the Company that could result if actual results vary from the assumptions and estimates. In management s opinion, the areas of the Company where the most significant judgment is exercised is in the valuation of pension plan assumptions, impairment estimates, contingency reserves, accrued removal obligations, regulatory assets and liabilities, unbilled revenue for OG&E, the allowance for uncollectible accounts receivable, the valuation of energy purchase and sale contracts and natural gas storage inventory and fair value and cash flow hedging policies. The selection, application and disclosure of the following critical accounting estimates have been discussed with the Company s audit committee.

Consolidated (including Electric Utility and Natural Gas Pipeline Segments)

Pension and other postretirement plan expenses and liabilities are determined on an actuarial basis and are affected by the market value of plan assets, estimates of the expected return on plan assets and assumed discount rates. 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. See Future Capital Requirements for a further discussion.

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 flows. An impairment loss is recognized when the sum of the expected future net cash flows is less than the carrying amount of the asset. The amount of any recognized impairment is based on the estimated fair value of the asset subject to impairment compared to the carrying amount of such asset. Enogex expects to continue to evaluate the strategic fit and financial performance of its assets in an effort to ensure a proper economic allocation of resources. The magnitude and timing of any impairment or gain on the disposition of assets that may be identified as not being strategic have not been determined.

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

In June 2001, the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standards (SFAS) No. 143, Accounting for Asset Retirement Obligations, which applies to legal obligations associated with the retirement of long-lived assets that result from the acquisition, construction, development and/or the normal operation of a long-lived asset. The scope of SFAS No. 143 includes the Company s accrued plant removal costs for generation, transmission, distribution, processing and pipeline assets. SFAS No. 143 requires that the fair value of a liability for an asset retirement obligation be recognized in the period in which it is incurred if a reasonable estimate of the fair value can be made. If a reasonable estimate of the fair value cannot be made in the period the asset retirement obligation is incurred, the liability shall be recognized when a reasonable estimate of the fair value can be made. In connection with the adoption of SFAS No. 143, the Company assessed whether it had a legal obligation within the scope of SFAS No. 143. The Company determined that it had a legal obligation to retire certain assets. As the Company currently has no plans to retire any of these assets and the remaining life is indeterminable, an asset retirement obligation was not recognized; however, the Company will monitor these assets and record a liability when a reasonable estimate of the fair value can be made. The Company adopted this new standard effective January 1, 2003 and the adoption of this new standard did not have a material impact on its consolidated financial position or results of operations.

OG&E and Enogex engage in cash flow and fair value hedge transactions to manage commodity risk and modify the rate composition of the debt portfolio. 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 hedging requirements and are executed based upon management established price targets. Enogex also utilizes fair value hedges under SFAS No. 133 to manage commodity price exposure for natural gas storage inventory. Hedges are evaluated prior to execution with respect to the impact on the volatility of forecasted earnings and are evaluated at least quarterly after execution for the impact on earnings. OG&E and Enogex have entered into interest rate swap agreements on the debt portfolio to modify the interest rate exposure on fixed rate debt issues. These interest rate swaps

qualify as fair value hedges under SFAS No. 133. The objective of these interest rate swaps was to achieve a lower cost of debt and to raise the percentage of total corporate long-term floating rate debt to reflect a level more in line with industry standards.

Electric Utility Segment

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 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 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. At December 31, 2003 and 2002, regulatory assets (excluding recoverable take or pay gas charges) of approximately $61.7 million and $78.6 million, respectively, are being amortized and reflected in rates charged to customers over periods of up to 20 years. Recoverable take or pay gas charges are not reflected in rates charged to customers. See Note 17 of Notes to Consolidated Financial Statements for a further discussion. At December 31, 2003 and 2002, regulatory liabilities (excluding fuel clause over recoveries) of approximately $116.3 million and $109.3 million, respectively, have been reclassified from Accumulated Depreciation in accordance with SFAS No. 143.

OG&E initially records certain costs: (i) that are probable of future recovery as a deferred charge until such time as the cost is approved by a regulatory authority, then the cost is reclassified as a regulatory asset; and (ii) that are probable of future liability as a deferred credit until such time as the amount is approved by a regulatory authority, then the amount is reclassified as a regulatory liability.

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, 2003, if the estimated usage or price used in the unbilled revenue calculation were to increase or decrease by one percent, this would cause a change in the unbilled revenues recognized of approximately $0.4 million. At December 31, 2003 and 2002, Accrued Unbilled Revenues were approximately $38.0 million and $28.2 million, respectively. The estimates that management uses in this calculation could vary from the actual amounts to be paid by customers.

Customer balances are generally written off if not collected within six months after the original due 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, 203, if the provision rate were to increase or decrease by 10 percent, this would cause a change in the uncollectible

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expense recognized of approximately $0.2 million. The allowance for uncollectible accounts receivable is a reduction to Accounts Receivable on the Consolidated Balance Sheets and is included in Other Operation and Maintenance Expense on the Consolidated Statements of Income. The allowance for uncollectible accounts receivable was approximately $2.6 million and $4.7 million at December 31, 2003 and 2002, respectively.

Natural Gas Pipeline Segment

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

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

OERI s activities include the marketing and trading of natural gas and natural gas liquids. The vast majority of these contracts expire within three years, which is when the cash aspect of the transactions will be realized. A substantial portion of these contracts qualify as derivatives under SFAS No. 133 and are marked-to-market with offsetting gains and losses recorded in earnings. In nearly all cases, independent market prices are obtained and compared to the values used for this mark-to-market valuation, and an oversight group outside of the marketing organization monitors all modeling methodologies and assumptions. The recorded value of the energy contracts may change significantly in the future as the market price for the commodity changes, but the value is still subject to the risk loss limitations provided under the Company s risk policies. The Company utilizes a model to estimate the fair value of its energy contracts including derivatives that do not have an independent market price. At December 31, 2003, unrealized mark-to-market gains were approximately $3.0 million, which included approximately $0.4 million of unrealized mark-to-market gains that were calculated utilizing models. At December 31, 2003, a price movement of one percent for prices verified by independent parties and a price movement of five percent on model-based prices would result in changes in unrealized mark-to-market gains of less than $0.1 million. Energy contracts are presented in Price Risk Management assets and liabilities on the Consolidated Balance Sheets and in Operating Revenues on the Consolidated Statements of Income. See Accounting Pronouncements below for a further discussion.

Effective January 1, 2003, natural gas storage inventory used in OERI s business activities are accounted for at the lower of cost or market in accordance with the guidance in EITF 02-3 which resulted in the rescission of EITF Issue No. 98-10, Accounting for Contracts

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Involved in Energy Trading and Risk Management Activities, as amended. Prior to January 1, 2003, this inventory was accounted for on a fair value accounting basis utilizing a gas index that in management s opinion approximated the current market value of natural gas in that region as of the Balance Sheet date. On April 1, 2003, natural gas storage inventory used in OERI s business activities began to be accounted for under SFAS No. 133. In order to minimize risk, OERI enters into contracts or hedging instruments to hedge the fair value of this inventory. For any contracts that qualify for hedge accounting under SFAS No. 133, the hedged portion of the inventory is recorded at fair value with an offsetting gain or loss recorded currently in earnings. Ineffectiveness associated with OERI s fair value hedge strategy was not material. The fair value of the hedging instrument is also recorded on the books of OERI as a Price Risk Management asset or liability with an offsetting gain or loss recorded in current earnings. At December 31, 2003, OERI had all natural gas inventory hedged with qualified fair value hedges under SFAS No. 133. As part of its recurring business activity, OERI injects and withdraws natural gas under the terms of storage capacity contracts; the amount of natural gas inventory was approximately $82.4 million and $32.9 million at December 31, 2003 and 2002, respectively. See Accounting Pronouncements below for a further discussion. Natural gas storage inventory is presented in Fuel Inventories on the Consolidated Balance Sheets and in Cost of Goods Sold on the Consolidated Statements of Income.

The allowance for uncollectible accounts receivable is established on a case-by-case basis when the Company believes the required payment of specific amounts owed is unlikely to occur. The allowance for uncollectible accounts receivable is a reduction to Accounts Receivable on the Consolidated Balance Sheets and is included in Other Operation and Maintenance Expense on the Consolidated Statements of Income. The allowance for uncollectible accounts receivable for the Natural Gas Pipeline segment was approximately $1.6 million and $8.9 million at December 31, 2003 and 2002, respectively.

Accounting Pronouncements

In June 2001, the FASB issued SFAS No. 143, which applies to legal obligations associated with the retirement of long-lived assets that result from the acquisition, construction, development and/or the normal operation of a long-lived asset. The scope of SFAS No. 143 includes the Company s accrued plant removal costs for generation, transmission, distribution, processing and pipeline assets. SFAS No. 143 requires that the fair value of a liability for an asset retirement obligation be recognized in the period in which it is incurred if a reasonable estimate of the fair value can be made. If a reasonable estimate of the fair value cannot be made in the period the asset retirement obligation is incurred, the liability shall be recognized when a reasonable estimate of the fair value can be made. Asset retirement obligations associated with long-lived assets included within the scope of SFAS No. 143 are those for which a legal obligation exists under enacted laws, statutes, written or oral contracts, including obligations arising under the doctrine of promissory estoppel. The recognition of an asset retirement obligation is capitalized as part of the carrying amount of the long-lived asset. Asset retirement obligations represent future liabilities and, as a result, accretion expense is accrued on this liability until such time as the obligation is satisfied. Adoption of SFAS No. 143 was required for financial statements issued for fiscal years beginning after June 15, 2002. The Company

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adopted this new standard effective January 1, 2003 and the adoption of this new standard did not have a material impact on its consolidated financial position or results of operations.

In connection with the adoption of SFAS No. 143, the Company assessed whether it had a legal obligation within the scope of SFAS No. 143. The Company determined that it had a legal obligation to retire certain assets. As the Company currently has no plans to retire any of these assets and the remaining life is indeterminable, an asset retirement obligation was not recognized; however, the Company will monitor these assets and record a liability when a reasonable estimate of the fair value can be made.

SFAS No. 143 also requires that, if the conditions of SFAS No. 71 are met, a regulatory asset or liability should be recorded to recognize differences between asset retirement costs recorded under SFAS No. 143 and legal or other asset retirement costs recognized for ratemaking purposes. Upon the application of SFAS No. 143, all rate regulated entities that are subject to the statement requirements will be required to quantify the amount of previously accumulated asset retirement costs and reclassify those differences as regulatory assets or liabilities. At December 31, 2002, approximately $109.3 million had been previously recovered from ratepayers and recorded as a liability in Accumulated Depreciation related to estimated asset retirement obligations. This balance was reclassified as a regulatory liability on the December 31, 2002 Consolidated Balance Sheet. At December 31, 2003, the regulatory liability for accrued removal obligations, net was approximately $116.3 million.

In July 2002, the FASB issued SFAS No. 146, Accounting for Costs Associated with Exit or Disposal Activities. SFAS No. 146 addresses financial accounting and reporting for costs associated with exit and disposal activities and supersedes EITF Issue No. 94-3, Liability Recognition for Certain Employee Termination Benefits and Other Costs to Exit an Activity (including Certain Costs Incurred in a Restructuring). SFAS No. 146 requires recognition of a liability for a cost associated with an exit or disposal activity when the liability is incurred, as opposed to when the entity commits to an exit plan under EITF 94-3. SFAS No. 146 also establishes that the liability should initially be measured and recorded at fair value. Adoption of SFAS No. 146 was required for exit and disposal activities initiated after December 31, 2002. The Company adopted this new standard effective January 1, 2003 and the adoption of this new standard did not have a material impact on its consolidated financial position or results of operations.

In October 2002, the EITF reached a consensus on certain issues covered in EITF 02-3. One consensus of EITF 02-3 requires that all mark-to-market gains and losses, whether realized or unrealized, on financial derivative contracts as defined in SFAS No. 133 be shown net in the Income Statement for financial statements issued for periods beginning after December 15, 2002, with reclassification required for prior periods presented. The Company adopted this consensus effective January 1, 2003 and the application of this consensus did not have a material impact on its consolidated financial position or results of operations as this consensus supports the Company s historical presentation of financial derivative contracts.

Another consensus reached in EITF 02-3 was to rescind EITF 98-10 effective for fiscal periods beginning after December 15, 2002. Effective October 25, 2002, all new contracts and

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physical inventories that would have been accounted for under EITF 98-10 were no longer marked to market through earnings unless the contracts met the definition of a derivative under SFAS No. 133. Application of the consensus for energy contracts and inventory that existed on or before October 25, 2002 that remain in effect at the date this consensus was initially applied were recognized as a cumulative effect of a change in accounting principle in accordance with Accounting Principles Board (APB) Opinion No. 20, Accounting Changes. As a result, only energy contracts that meet the definition of a derivative in SFAS No. 133 are carried at fair value. The Company adopted this consensus effective January 1, 2003 resulting in an approximate $9.6 million pre-tax loss ($5.9 million after tax). The loss, which was accounted for as a cumulative effect of a change in accounting principle during the first quarter of 2003, was primarily related to natural gas held in storage for trading purposes. This natural gas held in storage was sold during the first quarter of 2003 resulting in an increase in the gross margin on revenues in excess of the cumulative effect loss described above.

In December 2002, the FASB issued SFAS No. 148, Accounting for Stock-Based Compensation Transition and Disclosure an amendment of FASB Statement No. 123. SFAS No. 148 provides alternative methods of transition for a voluntary change to the fair value based method of accounting for stock-based employee compensation which includes the prospective method, modified prospective method and retroactive restatement method. SFAS No. 148 also amends the disclosure requirements of SFAS No. 123 to require prominent disclosures in both annual and interim financial statements about the method of accounting for stock-based employee compensation and the effect of the method used on reported results. Adoption of the annual disclosure and voluntary transition requirements of SFAS No. 148 is required for annual financial statements issued for fiscal years ending after December 15, 2002. Adoption of the interim disclosure requirements of SFAS No. 148 is required for interim periods beginning after December 15, 2002. Pursuant to the provisions of SFAS No. 123, the Company has elected to continue using the intrinsic value method of accounting for its stock-based employee compensation plans in accordance with APB Opinion No. 25, Accounting for Stock Issued to Employees. However, the Company has included the required disclosures under SFAS No. 148 in Note 1 of Notes to Consolidated Financial Statements. Also, see Note 10 of Notes to Consolidated Financial Statements for a further discussion.

In December 2002, the FASB issued Interpretation No. 45 which requires that at the time a company issues a guarantee, the company must recognize an initial liability for the fair value, or market value, of the obligations it assumes under that guarantee. Interpretation No. 45 is applicable on a prospective basis to guarantees issued or modified after December 31, 2002. The Company adopted this new interpretation effective January 1, 2003 and the adoption of this new interpretation did not have a material impact on its consolidated financial position or results of operations.

In January 2003, the FASB issued Interpretation No. 46 which requires the consolidation of entities in which an enterprise absorbs a majority of the entity s expected losses, receives a majority of the entity s expected residual returns, or both, as a result of ownership, contractual or other financial interests in the entity. Currently, entities are generally consolidated by an enterprise when it has a controlling financial interest through ownership of a majority voting interest in the entity.

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In October 2003, the FASB issued Interpretation No. 46-6, Effective Date of FASB Interpretation No. 46, Consolidation of Variable Interest Entities, in which the FASB agreed to defer, for public companies, the required effective dates to implement Interpretation No. 46 for interests held in a variable interest entity (VIE) or potential VIE that was created before February 1, 2003. For calendar year-end public companies, the deferral effectively moved the required effective date from the third quarter to the fourth quarter of 2003.

As a result of Interpretation No. 46-6, a public entity need not apply the provisions of Interpretation No. 46 to an interest held in a VIE or potential VIE until the end of the first interim or annual period ending after December 15, 2003, if the VIE was created before February 1, 2003 and the public entity has not issued financial statements reporting that VIE in accordance with Interpretation No. 46, other than in the disclosures required by Interpretation No. 46. Interpretation No. 46 may be applied prospectively with a cumulative-effect adjustment as of the date on which it is first applied or by restating previously issued financial statements for one or more years with a cumulative-effect adjustment as of the beginning of the first year restated. The Company adopted this new interpretation effective December 31, 2003 resulting in an approximate $0.8 million pre-tax gain ($0.5 million after tax). The adoption of this new interpretation resulted in the deconsolidation of the trust originated preferred securities of OGE Energy Capital Trust I, a wholly owned financing trust of the Company (see Note 12 of Notes to Consolidated Financial Statements), and the consolidation of Energy Insurance Bermuda Ltd. (EIB) Mutual Business Program No. 19 (MBP 19).

EIB is incorporated in Bermuda under the Companies Act of 1981, as amended. The Company began participating in EIB through MBP 19 on November 15, 1998. The Company is the sole participant in MBP 19. The Company has issued an $8.0 million standby letter of credit to MBP 19 for the benefit of insuring parts of the Company s property and liability insurance programs. MBP 19 was established to provide $15.0 million worth of property and liability insurance for the Company. The $8.0 million letter of credit was issued to provide protection for MBP 19 in case of large insurance claim losses. At December 31, 2003, there were no drawings against this letter of credit. This letter of credit renews automatically on an annual basis. Since a letter of credit was issued, the total equity investment at risk of MBP 19 is not sufficient to permit it to finance its activities without additional subordinated financial support from other parties. The Company significantly participates in the profits and losses of MBP 19, has the ability to participate significantly by input to EIB through the OGE Advisory Committee as provided by the Participation Agreement executed by the Company and EIB, has sole voting rights and has the obligation to absorb expected losses and the right to receive residual returns. Therefore, since the letter of credit was issued to EIB on behalf of MBP 19, MBP 19 is considered a VIE as defined in Interpretation No. 46 and the Company is the primary beneficiary which resulted in the consolidation of MBP 19 into the Company s Consolidated Financial Statements for the year ended December 31, 2003.

In April 2003, the FASB issued SFAS No. 149, Amendments of Statement 133 on Derivative Instruments and Hedging Activities. SFAS No. 149 amends and clarifies financial accounting and reporting for derivative instruments, including certain instruments embedded in other contracts and for hedging activities under SFAS No. 133. This statement requires that contracts with comparable characteristics be accounted for similarly. In particular, this statement

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clarifies under what circumstances a contract with an initial net investment meets the characteristic of a derivative, clarifies when a derivative contains a financing component, amends the definition of an underlying hedged risk to conform to language used in Interpretation No. 45 and amends certain other existing pronouncements. This statement, the provisions of which are to be applied prospectively, is effective for contracts entered into or modified after June 30, 2003 and for hedging relationships designated after June 30, 2003. The Company adopted this new standard effective July 1, 2003 and the adoption of this new standard did not have a material impact on its consolidated financial position or results of operations.

In May 2003, the FASB issued SFAS No. 150, Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity. SFAS No. 150 establishes standards for how an issuer classifies and measures certain financial instruments with characteristics of both liabilities and equity. The requirements of this statement apply to an issuer s classification and measurement of freestanding financial instruments, including those that comprise more than one option or forward contract. This statement does not apply to features that are embedded in a financial instrument that are not a derivative in its entirety. This statement also addresses questions about the classification of certain financial instruments that embody obligations to issue equity shares. SFAS No. 150 requires that instruments that are redeemable upon liquidation or termination of an issuing subsidiary that has a limited-life are considered mandatorily redeemable shares under SFAS No. 150 in the consolidated financial statements of the parent. Accordingly, these noncontrolling interests are required to be classified as liabilities under SFAS No. 150. All provisions of this statement, except the provisions related to a limited-life subsidiary, are effective for financial instruments entered into or modified after May 31, 2003, and otherwise are effective at the beginning of the first interim period beginning after June 15, 2003. Companies are not required to recognize noncontrolling interests of a limited-life subsidiary as a liability in the consolidated financial statements and should continue to account for these interests as minority interests until the FASB considers resulting implementation issues associated with the measurement and recognition guidance for these noncontrolling interests. Except for the provisions related to a limited-life subsidiary, the Company adopted this new standard effective July 1, 2003 and the adoption of this new standard did not have a material impact on its consolidated financial position or results of operations. The Company does not expect that the provisions related to a limited-life subsidiary will have a material impact on its consolidated financial position or results of operations.

In December 2003, the FASB issued SFAS No. 132 (Revised), Employers Disclosures about Pensions and Other Postretirement Benefits, an amendment of FASB Statements No. 87, 88 and 106. This Statement revised employers disclosures about pension plans and other postretirement benefits. It does not change the measurement or recognition of those plans required by FASB Statements No. 87, Employers Accounting for Pensions, No. 88, Employers Accounting for Settlements and Curtailments of Defined Benefit Pension Plans and for Termination Benefits, and No. 106, Employers Accounting for Postretirement Benefits Other Than Pensions. This Statement requires additional disclosures to those in the original Statement 132, Employers Disclosures about Pensions and Other Postretirement Benefits, for defined benefit pension plans and other defined benefit postretirement plans. Additional disclosures include information describing the types of plan assets, investment strategy, measurement date, plan obligations, cash flows and the components of net periodic benefit cost

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recognized during interim periods. Adoption of the provisions of this statement, except the provisions related to foreign plans and estimated future benefit payments, is required for financial statements issued for fiscal years ending after December 15, 2003. Adoption of the interim provisions of this statement is required for interim periods beginning after December 15, 2003. Adoption of the provisions of this statement related to foreign plans and estimated future benefit payments is required for financial statements issued for fiscal years ending after June 15, 2004. The Company adopted this new standard effective December 31, 2003 and the adoption of this new standard did not have a material impact on its consolidated financial position or results of operations.

Electric Competition; Regulation

State Restructuring Initiatives

Oklahoma

As previously reported, the Electric Restructuring Act of 1997 (the 1997 Act) was initially designed to provide retail customers in Oklahoma a choice of their electric supplier by July 1, 2002. Additional implementing legislation was to be adopted by the Oklahoma Legislature to address many specific issues associated with the 1997 Act and with deregulation. In May 2000, a bill addressing the specific issues of deregulation was passed in the Oklahoma State Senate and then was defeated in the Oklahoma House of Representatives. In May 2001, the Oklahoma Legislature postponed the scheduled start date for customer choice from July 1, 2002 until at least 2003. In addition to postponing the date for customer choice, this legislation called for a nine-member task force to further study the issues surrounding deregulation. The task force includes the Governor or his designee, the Oklahoma Attorney General, the OCC Chair and several legislative leaders, among others. In the 2003 legislative session, additional legislation was introduced to repeal the 1997 Act, but the 2003 legislative session ended without any further action to repeal the 1997 Act. It is unknown at this time whether the 1997 Act will be repealed. The Company will continue to actively participate in the legislative process and expects to remain a competitive supplier of electricity. As a result of the failures of California s attempt to deregulate its electricity markets, the Enron bankruptcy, and associated impacts on the industry, efforts to restructure the electricity market in Oklahoma appear at this time to be delayed indefinitely.

Arkansas

In April 1999, Arkansas passed a law (the Restructuring Law) calling for restructuring of the electric utility industry at the retail level. The Restructuring Law initially targeted customer choice of electricity providers by January 1, 2002. In February 2001, the Restructuring Law was amended to delay the start date of customer choice of electric providers in Arkansas until October 1, 2003, with the APSC having discretion to further delay implementation to October 1, 2005. In March 2003, the Restructuring Law was repealed. As part of the repeal legislation, electric public utilities are permitted to recover transition costs. OG&E incurred approximately $2.4 million in transition costs necessary to carry out its responsibilities associated with efforts to implement retail open access. On January 20, 2004, the APSC issued

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an order which authorized OG&E to recover approximately $1.9 million in transition costs over an 18-month period beginning February 2004.

National Energy Legislation

In December 2003 the U.S. Senate failed to pass a comprehensive Energy Bill that had long been debated in the Senate and the House of Representatives. The bill, as it was proposed, would have been largely beneficial to the Company. It contained provisions that would have minimized the risk of future uneconomic purchased power contracts being forced on the Company under PURPA as well as providing tax incentives for investment in the electric transmission and natural gas pipeline systems. The bill also provided favorable provisions for mandatory reliability oversight by the North American Electric Reliability Council with oversight by the FERC as well as the FERC citing authority for electric transmission in disputed areas. Also positive to the Company was that the bill did not contain any provisions for mandatory levels of renewable energy which would have had the effect of raising the Company s electric rates. Another significant provision of the Energy Bill was the repeal of the Public Utility Holding Company Act of 1935 which was of minimal impact to the Company.

When Congress reconvened in January 2004, the debate renewed over the Energy Bill. A compromise bill has been proposed in the Senate that would keep all of the issues important to the Company intact with the exception of the tax provisions. Excluding those provisions would eliminate the incentives for investment in the electric transmission and natural gas pipeline systems. It is unknown at this time what language will be contained in the final bill or when, or if, the bill is likely to be considered again in the Senate and the House of Representatives and, when or if, the bill ultimately will be approved.

Federal law imposes numerous responsibilities and requirements on OG&E. PURPA requires electric utilities, such as OG&E, to purchase power generated in a manufacturing process from a qualified cogeneration facility (QF). Generally stated, electric utilities must purchase electric energy and production capacity made available by QF s at a rate reflecting the cost that the purchasing utility can avoid as a result of obtaining energy and production capacity from these sources; rather than generating an equivalent amount of energy itself or purchasing the energy or capacity from other suppliers. OG&E has entered into agreements with four such cogenerators. Electric utilities also must furnish electric energy to QF s on a non-discriminatory basis at a rate that is just, reasonable and in the public interest and must provide certain types of service which may be requested by QF s to supplement or back up those facilities own generation.

Although efforts to increase competition at the state level have been stalled, there have been several initiatives implemented at the federal level to increase competition in the wholesale markets for electricity. The National Energy Policy Act of 1992 (Energy Act), among other things, promoted the development of IPPs. The Energy Act was followed by FERC Order 888 and Order 889, which facilitated third-party utilization of the transmission grid for sales of wholesale power. The Energy Act, Orders 888 and 889, and other FERC policies and initiatives have significantly increased competition in the wholesale power market. Utilities, including OG&E, have increased their own in-house wholesale marketing efforts and the number of

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entities with whom they historically traded. Moreover, power marketers became an increasingly important presence in the industry, however their importance has declined following the bankruptcy of Enron and the financial troubles of other significant power marketers. These entities typically arbitrage wholesale price differentials by buying power produced by others in one market and selling it in another. IPP s also are becoming a more significant sector of the electric utility industry. In both Oklahoma and Arkansas, significant additions of new power plants have been announced and, in some cases completed, almost all of it from IPP s.

Notwithstanding these developments in the wholesale power market, the FERC recognized that impediments remained to the achievement of fully competitive wholesale markets including: (i) engineering and economic inefficiencies inherent in the current operation and expansion of the transmission grid; and (ii) continuing opportunities for transmission owners (primarily electric utilities) to discriminate in the operation of their transmission facilities in favor of their own or affiliated power marketing activities. In the past, the FERC only encouraged utilities to join and place their transmission systems under the operational control of independent system operators (ISO). On December 20, 1999, the FERC issued Order 2000, its final rule on regional transmission organizations (RTO). Order 2000 is intended to have the effect of turning the nation s transmission facilities into independently operated common carriers that offer comparable service to all would-be-users. Although adopting a voluntary approach towards RTO formation, the FERC stressed that Order 2000 does not preclude it from requiring RTO participation. Order 2000 set out a timetable for every jurisdictional utility (including OG&E) to either join in an RTO filing, or, alternatively, to submit a filing describing its efforts to join an RTO, the reasons for not participating in an RTO proposal and any obstacles to participation, and its plans for further work toward participation.

OG&E is a member of the Southwest Power Pool (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 an Agency Agreement with the SPP to facilitate interstate transmission operations within this region in 1998. In October 2000, the SPP filed its application with the FERC to become an RTO. In July 2001, the FERC determined that the SPP did not have adequate scope and configuration to be granted RTO status. The SPP was encouraged to explore the possibility of joining an RTO to be formed in the southeastern region of the United States and then to explore the feasibility of becoming a part of the recently approved RTO being established by the Midwest Independent System Operator (MISO). The SPP and MISO entered negotiations during the late summer of 2001 to combine the SPP and MISO and to form a new regional transmission entity that would combine the MISO and SPP organizations, capture certain synergies that would be available from the combined organization, and allow member companies in the SPP certain options with respect to membership in the combined organization. However, for a variety of reasons, MISO and SPP terminated their proposed combination in March 2003. OG&E remained a member of the SPP while the MISO/SPP combination was pending, and OG&E participated with the SPP and other SPP members to evaluate the next steps necessary for compliance with the FERC s Order 2000. In the meantime, the SPP continued to offer open access transmission service in the SPP region under the SPP Open Access Transmission Tariff. On October 15, 2003, the SPP filed an application with the FERC seeking authority to form an RTO. On February 10, 2004, the FERC

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conditionally approved the SPP s application. The SPP must meet certain conditions before it may commence operations as an RTO. Termination of the proposed MISO/SPP combination and recent conditional approval of the SPP RTO application are not expected to significantly impact the Company s consolidated financial results.

In October 2001, the FERC issued a Notice of Proposed Rulemaking proposing to adopt new standards of conduct rules applicable to all jurisdictional electric and natural gas transmission providers. The proposed rules would replace the current rules governing the electric transmission and wholesale electric functions of electric utilities and the rules governing natural gas transportation and wholesale gas supply functions. The proposed rules would expand the definition of affiliate and further limit communications between transmission functions and supply functions, and could materially increase operating costs of market participants, including OG&E and Enogex. In April 2002, the FERC Staff issued a reaction paper, generally rejecting the comments of parties opposed to the proposed rules. On November 25, 2003, the FERC issued its new rules regulating the relationship between electric and gas transmission providers and those entities merchant personnel and energy affiliates. The FERC s final rule requires all transmission providers to be in full compliance with the new rules by June 1, 2004. In February 2004, OG&E and Enogex submitted plans and schedules to take the necessary actions to be in compliance with these new rules and expect that their initial costs to comply with the final rule will not exceed $1.6 million in 2004. The final rule is currently before the FERC on rehearing. Any changes to the final rule on rehearing could affect the anticipated compliance costs.

In July 2002, the FERC issued a Notice of Proposed Rulemaking on Standard Market Design Rulemaking for regulated utilities. If implemented as proposed, the rulemaking will substantially change how wholesale electric markets operate throughout the United States. The proposed rulemaking expands the FERC s intent to unbundle transmission operations from integrated utilities and ensure robust competition in wholesale markets. The proposed rule contemplates that all wholesale and retail customers will take transmission service under a single network transmission service tariff. The rule also contemplates the implementation of a bid-based system for buying and selling energy in wholesale markets. RTOs or Independent Transmission Providers will administer the market. RTOs will also be responsible for regional plans that identify opportunities to construct new transmission, generation or demand side programs to reduce transmission constraints and meet regional energy requirements. Finally, the rule envisions the development of Regional Market Monitors responsible for ensuring the individual participants do not exercise unlawful market power. On April 28, 2003, the FERC issued a White Paper, Wholesale Market Platform , in which the FERC indicated that it will change the proposed rule as reflected in the White Paper and following additional regional technical conferences. The FERC committed in the White Paper to work with interested parties including state commissions to find solutions that will recognize regional differences within regions subject to the FERC s jurisdiction. Thus far, the FERC has held conferences in Boston, Omaha, Wilmington, Tallahassee, Phoenix, New York and San Francisco.

In October 2003, the FERC issued new rules governing corporate money pools, which include jurisdictional public utility or pipeline subsidiaries of nonregulated parent companies. The rules require documentation of transactions within such money pools and notification to the FERC if the common equity ratio of the utility falls below 30 percent.

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The FERC requires all utilities authorized to sell power at market-based rates to file updated market power analyses every three years. In December 2003, OG&E filed its updated market power analysis with the FERC.

Regulatory Assets and Liabilities

OG&E, as a regulated utility, is subject to the accounting principles prescribed by SFAS No. 71. SFAS No. 71 provides that certain 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 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 initially records certain costs: (i) that are probable of future recovery as a deferred charge until such time as the cost is approved by a regulatory authority, then the cost is reclassified as a regulatory asset; and (ii) that are probable of future liability as a deferred credit until such time as the amount is approved by a regulatory authority, then the amount is reclassified as a regulatory liability.

At December 31, 2003 and 2002, OG&E had regulatory assets of approximately $94.2 million and $111.1 million, respectively, and regulatory liabilities of approximately $148.7 million and $109.3 million, respectively. Approximately 45 percent of the regulatory assets and liabilities are allocated to OG&E s electric generation assets and approximately 55 percent of the regulatory assets and liabilities are allocated to OG&E s electric transmission and distribution assets.

As discussed previously, legislation was enacted in Oklahoma and Arkansas that was to restructure the electric utility industry in those states. The Arkansas legislation was repealed and implementation of the Oklahoma restructuring legislation has been delayed and seems unlikely to proceed during the near future. Yet, if and when implemented this legislation would deregulate OG&E s electric generation assets and cause the Company to discontinue the use of SFAS No. 71, with respect to its related regulatory balances. This may result in either full recovery of generation-related regulatory assets (net of related regulatory liabilities) or a non-cash, pre-tax write-off as an extraordinary charge, depending on the transition mechanisms developed by the legislature for the recovery of all or a portion of these net regulatory assets.

The previously enacted Oklahoma and Arkansas legislation would not affect OG&E s electric transmission and distribution assets and the Company believes that the continued use of SFAS No. 71 with respect to the related regulatory balances is appropriate. However, if utility regulators in Oklahoma and Arkansas were to adopt regulatory methodologies in the future that are not based on the cost-of-service, the continued use of SFAS No. 71 with respect to the regulatory balances related to the electric transmission and distribution assets may no longer be 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.

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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.

Commitments and Contingencies

In the normal course of business, the Company is confronted with issues or events that may result in a contingent liability. These generally relate to lawsuits, claims made by third parties, environmental actions or the action of various regulatory agencies. Management consults with 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 set forth below, management, after consultation with legal counsel, does not anticipate that liabilities arising out of currently pending or threatened lawsuits and claims will have a material adverse effect on the Company s consolidated financial position, results of operations or cash flows. This assessment of currently pending or threatened lawsuits is subject to change.

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

In 1998, Enogex entered into a Storage Lease Agreement (the Agreement) with Central Oklahoma Oil and Gas Corp. (COOG). Under the Agreement, COOG agreed to make certain enhancements to the Stuart Storage Facility to increase capacity and deliverability of the facility. In 1999 a dispute arose as to whether the natural gas deliverability for the Stuart Storage Facility was being provided by COOG and these issues were submitted to arbitration in October and November 2001. In July 2002, the Oklahoma District Court affirmed the arbitration award and entered judgment against COOG and in favor of Enogex in the amount of approximately $23.3 million (the Judgment).

On July 24, 2002, Enogex exercised the asset purchase option provided in the Agreement and title to the Stuart Storage Facility was transferred to Enogex on October 24, 2002, effective August 9, 2002 (the date COOG turned over operations of the facility to Enogex). As part of the Agreement, the Company agreed in 1998 to make up to a $12 million secured loan to Natural Gas Storage Corporation (NGSC), an affiliate of COOG (the NGSC Loan). Since June 2003, NGSC has failed and refused to repay the NGSC Loan. As of December 31, 2003, the amount outstanding under the NGSC Loan was approximately $8.0 million plus accrued interest.

On August 12, 2002, the Company received a petition in a legal proceeding filed by COOG and NGSC against the Company and Enogex in Texas. COOG and NGSC stated a claim for declaratory judgment asserting, among other things, that NGSC is not obligated to make payments on the NGSC Loan based on various theories and, that: (1) the Company was obligated

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to demand Enogex make the requisite payments to the Company; (2) the Company is liable to NGSC for failing to demand the requisite payments from Enogex, or alternatively, NGSC is entitled to a reduction in the amount it owes to the Company; (3) Enogex was and is obligated to make the payments to the Company until the indebtedness of NGSC to the Company is reduced to zero; (4) Enogex is not entitled to set off the Judgment against the lease payments that it originally owed to COOG and now owes to the Company; (5) no event of default has occurred; and (6) under the Agreement, the only remedy Enogex had or has if the Stuart Storage Facility did not perform was to seek a modification of the lease payments based upon COOG s expert s analysis of the performance of the Stuart Storage Facility. COOG and NGSC have also stated claims for breach of contract relating to the same allegations in its claim for declaratory relief and include claims for attorneys fees.

The Company objected to being sued in Texas because the Texas Court does not have proper jurisdiction over the Company. On September 24, 2002, Enogex filed an answer in response to the allegations, asserting, among other things, that the disputed issues have already been properly determined by the Arbitration Panel and the Oklahoma Court and, therefore, this action is improper.

On February 27, 2003, Enogex sent its arbitration demand to plaintiffs (COOG and NGSC) regarding the issues between plaintiffs and Enogex in the Texas action, and Enogex named its arbitrator. On February 28, 2003, Enogex filed a motion to dismiss, or in the alternative, to abate, stay and compel arbitration in the Texas action. By Order dated June 19, 2003, the Court granted Enogex s request for arbitration and ordered COOG/NGSC and Enogex to arbitration on all issues and claims arising under the Agreement and/or the asset purchase option, including all issues overlapping with the loan agreement and related documents. The Texas action is stayed in its entirety pending arbitration. Under the arbitration provisions in the Agreement, a final arbitration decision is to be rendered by June 30, 2004.

On July 16, 2003, the Company and Enogex served separate complaints on the individual shareholders of COOG and NGSC Enogex Inc. v John C. Thrash, John F. Thrash and Robert R. Voorhees, Jr., Case No. CIV-03-0388-L; and OGE Energy Corp. and Enogex Inc. v John C. Thrash, John F. Thrash and Robert R. Voorhees, Jr., Case No. CIV 03-0389-L both filed in the Western District of Oklahoma Federal Court. The Company and Enogex have each stated claims for (1) fraudulent transfer; (2) imposition of an equitable trust; and (3) breach of fiduciary duty.

The Company intends to continue to vigorously pursue its rights in conjunction with the remaining amount owed under the Judgment, plus interest, and the Company and Enogex seek to recover the amount owed under the NGSC Loan, plus interest.

Natural Gas Measurement Cases

Grynberg On June 15, 1999, the Company was served with plaintiff s complaint, which is a qui tam action under the False Claims Act in the United States District Court, State of Oklahoma by plaintiff Jack J. Grynberg, as individual relator on behalf of the United States Government, alleging: (i) each of the named defendants have improperly or intentionally mismeasured gas (both volume and British thermal unit (Btu) content) purchased from federal

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

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

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

In October 2002, the Court granted the Department of Justice s motion to dismiss certain of Plaintiff s claims and issued an order dismissing Plaintiff s valuation claims against all defendants. Various procedural motions have been filed. Discovery is proceeding on limited jurisdiction issues as ordered by the Court. The deposition of relator Grynberg began in December 2002, and continued during 2003.

The Company intends to vigorously defend this action. Since the case is in the early stages of motions and discovery, 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 at this time.

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

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The Company intends to vigorously defend this action. Since the case is in the early stages of motions and discovery, 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 at this time.

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 two only royalty owners either from whom the defendants had purchased natural gas or measured natural gas since January 1, 1974 to the present. The class action petition alleges improper analysis of gas heating content. In all other respects, the Price II petition appears to be the same as the amended petition in Price I. Discovery on class certification is proceeding.

The Company intends to vigorously defend this action. Since the case is in the early stages of motions and discovery, 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 at this time.

Farmland Industries

Farmland Industries, Inc. (Farmland) voluntarily filed for Chapter 11 bankruptcy protection from creditors on May 31, 2002. Enogex provided gas transportation and supply services to Farmland, and is an unsecured creditor of Farmland. Enogex filed its Proof of Claim on January 7, 2003, for approximately $5.4 million. In April 2003, Enogex negotiated a settlement and received approximately $1.9 million in May 2003.

On July 31, 2003, Farmland filed its Disclosure Statement for its Reorganization Plan for approval by the bankruptcy court. According to the Disclosure Statement, Farmland proposes to pay its general unsecured creditors an amount between 60 percent and 82 percent on their pre-petition claims. As a general unsecured creditor of Farmland and pursuant to the terms of the Settlement Agreement referenced above, Enogex s recovery under the proposed distribution would be approximately $0.8 million, which is in addition to the $1.9 million Enogex received in May 2003.

Agreement with Colorado Interstate Gas Company

In December 2002, Enogex entered into an agreement with Colorado Interstate Gas Company (CIG) regarding reservation of capacity on a proposed interstate gas pipeline (the Cheyenne Plains Pipeline). If completed, the Cheyenne Plains Pipeline would provide interstate gas transportation services in the states of Wyoming, Colorado and Kansas with a capacity of 560,000 decatherms/day (Dth/day). Under this agreement, Enogex bid to reserve 60,000 Dth/day of capacity on the proposed pipeline for 10 years and two months. Such reservation would result in Enogex having access to significant additional natural gas supplies in the areas to be served by the proposed pipeline. Subject to regulatory and other approvals, CIG

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is proposing an in-service date no later than August 31, 2005. Cheyenne Plains continues to seek resolution of various environmental issues associated with the proposed construction of the pipeline, and is in the process of acquiring pipeline, equipment and rights of way for the project.

Guarantees

During the normal course of business, Enogex issues guarantees on behalf of its subsidiaries for the purpose of securing credit for certain business activities. These guarantees are for payment when due of amounts payable by its subsidiaries under various agreements with counterparties. At December 31, 2003, accounts payable supported by guarantees was approximately $65.6 million. Since these guarantees by Enogex represent security for payment of payables obtained in the normal course of its subsidiaries business activities, the Company, on a consolidated basis, does not assume any additional liability as a result of this arrangement.

OGE Energy Corp. has issued a $5.0 million guarantee on behalf of OERI and a $15.0 million guarantee on behalf of Enogex Inc. for the purpose of securing credit for certain business activities. These guarantees are for payment when due of amounts payable by OERI and Enogex Inc. under various agreements with counterparties. In December 2003, the guarantee issued on behalf of Enogex Inc. expired and the guarantee issued on behalf of OERI was increased to $7.0 million, of which there is approximately a $1.9 million outstanding liability balance related to this guarantee at December 31, 2003. Since this guarantee by OGE Energy Corp. represents security for payment of payables obtained in OERI s business activities, the Company, on a consolidated basis, does not assume any additional liability as a result of this arrangement.

The Company has issued an $8.0 million standby letter of credit to MBP 19 for the benefit of insuring parts of the Company s property and liability insurance programs. MBP 19 was established to provide $15.0 million worth of property and liability insurance for the Company. The $8.0 million letter of credit was issued to provide protection for MBP 19 in case of large insurance claim losses. At December 31, 2003, there were no drawings against this letter of credit. This letter of credit renews automatically on an annual basis.

At December 31, 2003, 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 $6.7 million of collateral to satisfy its obligation under its financial and physical contracts.

Pending Acquisition of Power Plant

On August 18, 2003, OG&E signed an asset purchase agreement to acquire NRG McClain LLC s 77 percent interest in the McClain Plant. Closing has been delayed pending receipt of FERC approval. The acquisition of this interest in the McClain Plant would clearly constitute an acquisition of New Generation under the Settlement Agreement. The purchase price for the interest in the McClain Plant is approximately $159.9 million, subject to adjustment for prepaid gas and property taxes. See Note 18 of Notes to Consolidated Financial Statements for a description of current proceedings involving a PowerSmith QF contract.

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Sooner Power Plant Coal Dust Explosion

On February 16, 2004, there was a coal dust explosion at OG&E s Sooner Power Plant which caused structural and electrical damage to the coal train unloading system. The generation capacity of the Sooner Plant facility has not been impacted by this incident. The estimated damage costs are between approximately $3.0 million and $4.0 million. The Company expects that the coal train unloading system will be ready to unload coal trains by April 2, 2004. In the meantime, Sooner Power Plant continues to generate power by using coal from the storage pile. The Company is self-insured for this loss.

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Quantitative and Qualitative Disclosures About Market Risk.

Risk Management

The risk management process established by the Company is designed to measure both quantitative and qualitative risks in its businesses. A corporate risk management department, under the direction of a corporate risk oversight management committee, has been established to review these risks on a regular basis. The Company is exposed to market risk in its normal course of business, including changes in certain commodity prices and interest rates. The Company also engages in price risk management activities for both trading and non-trading purposes.

To manage the volatility relating to these exposures, the Company enters into various derivative transactions pursuant to the Company s policies on hedging practices. Derivative positions are monitored using techniques such as mark-to-market valuation, value-at-risk and sensitivity analysis.

Interest Rate Risk

The Company s exposure to changes in interest rates relates primarily to long-term debt obligations 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 may utilize interest rate derivatives to alter interest rate exposure in an attempt to reduce interest rate 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.

At December 31, 2003 and 2002, the Company had three outstanding interest rate swap agreements: (i) OG&E entered into an interest rate swap agreement, effective March 30, 2001, to convert $110.0 million of 7.30 percent fixed rate debt due October 15, 2025, to a variable rate based on the three month LIBOR and (ii) Enogex entered into two separate interest rate swap agreements, effective July 15, 2002 and October 24, 2002, to convert $100.0 million of 8.125 percent fixed rate debt due January 15, 2010, to a variable rate based on the six month LIBOR. The objective of these interest rate swaps was to achieve a lower cost of debt and to raise the percentage of total corporate long-term floating rate debt to reflect a level more in line with industry standards. These interest rate swaps qualified as fair value hedges under SFAS No. 133 and met all of the requirements for a determination that there was no ineffective portion as allowed by the shortcut method under SFAS No. 133.

At December 31, 2003 and 2002, the fair values pursuant to the interest rate swaps were approximately $7.6 million and $15.9 million, respectively, and are classified as Deferred Charges and Other Assets Price Risk Management in the accompanying Consolidated Balance Sheets. A corresponding net increase of approximately $7.6 million and $15.9 million was reflected in Long-Term Debt at December 31, 2003 and 2002, respectively, as these fair value hedges were effective at December 31, 2003 and 2002.

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On April 6, 2001, the Company entered into a one-year interest rate swap agreement to lock in a fixed rate of 4.41 percent, effective April 10, 2001, on $140.0 million of variable rate short-term debt. The objective of this interest rate swap was to achieve a lower cost of debt and to reduce exposure to short-term interest rate volatility associated with the Company s commercial paper program. This interest rate swap initially qualified for hedge accounting treatment as a cash flow hedge under SFAS No. 133. However, due to unexpected changes in the level of commercial paper issued during the third quarter of 2001, hedge accounting treatment under SFAS No. 133 was discontinued as of July 1, 2001, and all subsequent changes in the fair value of the swap were recorded as Interest Expense. During 2002 and 2001, approximately $0.2 million and $1.3 million, respectively, were recorded as Interest Expense in the accompanying Consolidated Statements of Income. At December 31, 2002, no amounts were included in Accumulated Other Comprehensive Loss related to this cash flow hedge. As of December 31, 2001, approximately a $0.1 million after tax loss was included in Accumulated Other Comprehensive Loss related to this cash flow hedge.

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. The valuation of the Company s interest rate swaps was determined primarily based on quoted market prices. The following table shows the Company s long-term debt maturities and the weighted-average interest rates by maturity date.

(Dollars in millions)	2004	2005	2006	2007	2008	Thereafter	Total	2003 Year-end Fair Value
Fixed rate debt								
Principal amount	$ 53.1	$ 146.4	$ 2.2	$ 5.2	$ 3.2	$ 821.0	$ 1,031.1	$ 1,180.8
Weighted-average interest rate	7.22%	7.07%	7.13%	7.78%	7.11%	7.44%	7.38%	---
Variable rate debt								
Principal amount (A)	---	---	---	---	---	$ 458.3	$ 458.3	$ 458.9
Weighted-average interest rate	---	---	---	---	---	3.09%	3.09%	---

(A) Amount includes an increase to the fair value of long-term debt of approximately $7.6 million due to the Company s interest rate swaps.

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 are broken into trading, which includes transactions that are voluntarily entered into to capture subsequent changes in commodity prices, and non-trading, which result from the exposure some of the Company s assets have to commodity prices.

The trading activities are conducted throughout the year subject to daily and monthly trading stop loss limits of $2.5 million. The daily loss exposure from trading activities is

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measured primarily using value at risk as well as other quantitative risk measurement techniques and is limited to $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.

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 operating income received by the Company as compensation for operating some of its assets. To partially reduce non-trading commodity price risk incurred in the Company s normal course of business caused by these market fluctuations, the Company may hedge, through the utilization of derivatives, the effects these market fluctuations have on the operating income received by the Company as compensation for operating these assets. Because the commodities covered by these derivatives 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 trading and non-trading commodity price exposure to the market risk of the Company s natural gas and natural gas liquids commodity positions. 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. The fair value of such position is a summation of the fair values calculated for each commodity by valuing each net position at quoted market prices. Market risk is estimated as the potential loss in fair value resulting from a hypothetical 10 percent adverse change in such prices over the next 12 months. The results of this analysis, which may differ from actual results, are as follows for 2003:

(In millions)	Trading	Non-Trading
Commodity market risk, net	$ ---	$ 3.9

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Financial Statements and Supplementary Data.

OGE ENERGY CORP.
CONSOLIDATED BALANCE SHEETS

December 31 *(In millions)*	**2003**	2002
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	**$ 245.6**	$ 44.4
Accounts receivable, net	**350.2**	304.6
Accrued unbilled revenues	**38.0**	28.2
Fuel inventories	**163.3**	99.7
Materials and supplies, at average cost	**45.1**	42.6
Price risk management	**61.3**	17.1
Gas imbalance	**70.0**	47.8
Accumulated deferred tax assets	**9.4**	10.9
Fuel clause under recoveries	**4.0**	14.7
Other	**21.5**	10.6
Current assets of discontinued operations	---	4.7
Total current assets	**1,008.4**	625.3
OTHER PROPERTY AND INVESTMENTS, at cost	**34.7**	27.2
PROPERTY, PLANT AND EQUIPMENT		
In service	**5,596.3**	5,488.0
Construction work in progress	**56.7**	44.8
Other	**15.0**	30.5
Total property, plant and equipment	**5,668.0**	5,563.3
Less accumulated depreciation	**2,358.5**	2,232.3
Net property, plant and equipment	**3,309.5**	3,331.0
In service of discontinued operations	**---**	54.2
Less accumulated depreciation	**---**	11.4
Net property, plant and equipment of discontinued operations	**---**	42.8
Net property, plant and equipment	**3,309.5**	3,373.8
DEFERRED CHARGES AND OTHER ASSETS		
Recoverable take or pay gas charges	**32.5**	32.5
Income taxes recoverable from customers, net	**31.6**	34.8
Intangible asset - unamortized prior service cost	**40.2**	42.7
Prepaid benefit obligation	**55.7**	44.9
Price risk management	**13.5**	20.1
Other	**58.6**	63.4
Deferred charges and other assets of discontinued operations	**---**	0.2
Total deferred charges and other assets	**232.1**	238.6
TOTAL ASSETS	**$ 4,584.7**	$ 4,264.9

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)*	**2003**	2002
LIABILITIES AND STOCKHOLDERS EQUITY		
CURRENT LIABILITIES		
Short-term debt	**$ 202.5**	$ 275.0
Accounts payable	**280.2**	261.5
Dividends payable	**29.1**	26.1
Customers deposits	**41.6**	40.6
Accrued taxes	**18.7**	23.6
Accrued interest	**30.7**	35.7
Accrued interest - unconsolidated affiliate	**3.5**	---
Tax collections payable	**7.9**	6.7
Accrued vacation	**17.2**	16.9
Long-term debt due within one year	**52.1**	19.8
Non-recourse debt of joint venture	**1.2**	1.2
Price risk management	**46.9**	13.9
Gas imbalance	**22.5**	22.9
Fuel clause over recoveries	**32.4**	---
Other	**41.2**	19.3
Current liabilities of discontinued operations	**---**	2.0
Total current liabilities	**827.7**	765.2
LONG-TERM DEBT		
Long-term debt	**1,189.7**	1,460.5
Non-recourse debt of joint venture	**40.2**	41.4
Long-term debt - unconsolidated affiliate	**206.2**	---
Total long-term debt	**1,436.1**	1,501.9
DEFERRED CREDITS AND OTHER LIABILITIES		
Accrued pension and benefit obligations	**167.4**	184.2
Accumulated deferred income taxes	**747.3**	627.0
Accumulated deferred investment tax credits	**42.0**	47.1
Accrued removal obligations, net	**116.3**	109.3
Price risk management	**4.5**	0.6
Provision for payments of take or pay gas	**32.5**	32.5
Other	**9.3**	4.1
Deferred credits and other liabilities of discontinued operations	**---**	9.1
Total deferred credits and other liabilities	**1,119.3**	1,013.9
STOCKHOLDERS EQUITY		
Common stockholders equity	**636.1**	453.5
Retained earnings	**623.9**	604.7
Accumulated other comprehensive loss, net of tax	**(58.4)**	(74.3)
Total stockholders equity	**1,201.6**	983.9

TOTAL LIABILITIES AND STOCKHOLDERS EQUITY	**$4,584.7**	$ 4,264.9

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

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OGE ENERGY CORP.
CONSOLIDATED STATEMENTS OF CAPITALIZATION

December 31 *(In millions)*				**2003**	2002
STOCKHOLDERS EQUITY					
Common stock, par value $0.01 per share; authorized 125.0 shares; and outstanding 87.4 and 78.5 shares, respectively				**$ 0.9**	$ 0.8
Premium on capital stock				**635.2**	452.7
Retained earnings				**623.9**	604.7
Accumulated other comprehensive loss, net of tax				**(58.4)**	(74.3)
Total stockholders equity				**1,201.6**	983.9
LONG-TERM DEBT					
SERIES	DATE DUE				
Senior Notes-OG&E					
7.125 %	Senior Notes, Series Due October 15, 2005	**110.0**	110.0		
6.500 %	Senior Notes, Series Due July 15, 2017	**125.0**	125.0		
Variable %	Senior Notes, Series Due October 15, 2025	**114.0**	117.5		
6.650 %	Senior Notes, Series Due July 15, 2027	**125.0**	125.0		
6.500 %	Senior Notes, Series Due April 15, 2028	**100.0**	100.0		
Other bonds-OG&E					
Variable %	Garfield Industrial Authority, January 1, 2025	**47.0**	47.0		
Variable %	Muskogee Industrial Authority, January 1, 2025	**32.4**	32.4		
Variable %	Muskogee Industrial Authority, June 1, 2027	**56.0**	56.0		
Unamortized premium and discount, net		**(2.2)**	(2.4)		
Enogex notes					
6.60% - 8.28%	Medium-Term Notes, Series Due 2003	**---**	19.0		
6.71% - 8.34%	Medium-Term Notes, Series Due 2004	**51.0**	51.0		
6.81% - 6.99%	Medium-Term Notes, Series Due 2005	**34.2**	34.2		
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	**200.0**	200.0		
Variable %	Medium-Term Notes, Series Due 2010	**209.5**	215.2		
7.15%	Medium-Term Notes, Series Due 2018	**69.0**	71.0		
7.00%	Medium-Term Notes, Series Due 2020	**8.3**	8.0		
7.75%	Medium-Term Notes Series Due 2023	**---**	10.0		
Trust Originated Preferred Securities (Note 12)		**---**	200.0		
Unconsolidated affiliate (Note 12)		**206.2**	---		
Total long-term debt				**1,489.4**	1,522.9
Less long-term debt due within one year				**52.1**	19.8
Non-recourse of joint venture				**1.2**	1.2
Total long-term debt (excluding long-term debt due within one year)				**1,436.1**	1,501.9

Total Capitalization	**$2,637.7**	$ 2,485.8

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

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OGE ENERGY CORP.
CONSOLIDATED STATEMENTS OF INCOME

Year ended December 31 *(In millions, except per share data)*	**2003**	2002	2001
OPERATING REVENUES			
Electric Utility operating revenues	**$1,517.1**	$ 1,388.0	$ 1,456.8
Natural Gas Pipeline operating revenues	**2,261.9**	1,635.9	1,607.6
Total operating revenues	**3,779.0**	3,023.9	3,064.4
COST OF GOODS SOLD			
Electric Utility cost of goods sold	**792.7**	662.2	730.2
Natural Gas Pipeline cost of goods sold	**2,053.3**	1,458.1	1,455.4
Total cost of goods sold	**2,846.0**	2,120.3	2,185.6
Gross margin on revenues	**933.0**	903.6	878.8
Other operation and maintenance	**371.7**	370.0	370.3
Depreciation	**176.9**	182.5	172.9
Impairment of assets	**10.2**	50.1	---
Taxes other than income	**67.3**	65.3	64.7
OPERATING INCOME	**306.9**	235.7	270.9
OTHER INCOME (EXPENSE)			
Other income	**8.1**	3.7	3.1
Other expense	**(9.0)**	(4.7)	(4.2)
Net other income (expense)	**(0.9)**	(1.0)	(1.1)
INTEREST INCOME (EXPENSE)			
Interest income	**1.3**	1.7	4.2
Interest on long-term debt	**(75.2)**	(86.2)	(98.2)
Interest on trust preferred securities	**---**	(17.3)	(17.3)
Interest expense - unconsolidated affiliate	**(17.3)**	---	---
Allowance for borrowed funds used during construction	**0.5**	0.9	0.7
Interest on short-term debt and other interest charges	**(6.0)**	(8.2)	(12.4)
Net interest expense	**(96.7)**	(109.1)	(123.0)
INCOME FROM CONTINUING OPERATIONS BEFORE TAXES	**209.3**	125.6	146.8
INCOME TAX EXPENSE	**73.7**	44.6	52.9
INCOME FROM CONTINUING OPERATIONS BEFORE CUMULATIVE EFFECT OF CHANGE IN ACCOUNTING PRINCIPLE	**135.6**	81.0	93.9
DISCONTINUED OPERATIONS (NOTE 4)			
Income from discontinued operations	**1.8**	8.4	6.4
Income tax expense (benefit)	**2.2**	(1.4)	(0.3)

Income (loss) from discontinued operations	**(0.4)**	9.8	6.7
INCOME BEFORE CUMULATIVE EFFECT OF CHANGE IN ACCOUNTING PRINCIPLE	**135.2**	90.8	100.6
CUMULATIVE EFFECT ON PRIOR YEARS OF CHANGE IN ACCOUNTING PRINCIPLE, net of tax of $3.4	**(5.4)**	---	---
NET INCOME	**$ 129.8**	$ 90.8	$ 100.6
BASIC AVERAGE COMMON SHARES OUTSTANDING	**81.8**	78.1	77.9
DILUTED AVERAGE COMMON SHARES OUTSTANDING	**82.1**	78.2	77.9
BASIC EARNINGS PER AVERAGE COMMON SHARE			
Income from continuing operations	**$ 1.66**	$ 1.04	$ 1.20
Income from discontinued operations, net of tax	**---**	0.12	0.09
Loss from cumulative effect of accounting change, net of tax	**(0.07)**	---	---
NET INCOME	**$ 1.59**	$ 1.16	$ 1.29
DILUTED EARNINGS PER AVERAGE COMMON SHARE			
Income from continuing operations	**$ 1.65**	$ 1.04	$ 1.20
Income from discontinued operations, net of tax	**---**	0.12	0.09
Loss from cumulative effect of accounting change, net of tax	**(0.07)**	---	---
NET INCOME	**$ 1.58**	$ 1.16	$ 1.29
DIVIDENDS DECLARED PER SHARE	**$ 1.33**	$ 1.33	$ 1.33

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

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OGE ENERGY CORP.
CONSOLIDATED STATEMENTS OF RETAINED EARNINGS

Year ended December 31 *(In millions)*	**2003**	2002	2001
BALANCE AT BEGINNING OF PERIOD	**$ 604.7**	$ 617.9	$ 621.0
ADD: Net income	**129.8**	90.8	100.6
Total	**734.5**	708.7	721.6
DEDUCT: Dividends declared on common stock	**110.6**	104.0	103.7
BALANCE AT END OF PERIOD	**$ 623.9**	$ 604.7	$ 617.9

OGE ENERGY CORP.
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Year ended December 31 *(In millions)*	**2003**	2002	2001
Net income	**$ 129.8**	$ 90.8	$ 100.6
Other comprehensive income (loss), net of tax:			
Minimum pension liability adjustment [$23.8, ($85.5) and ($35.8) pre-tax,			

respectively]	**14.6**	(52.4)	(21.9)
Transition adjustment [($26.9) pre-tax]	**---**	---	(16.5)
Gain on qualifying cash flow hedge (total gain less ineffective portion) [$21.4 pre-tax]	**---**	---	13.1
Reclassification adjustments - transition adjustment [$26.9 pre-tax]	**---**	---	16.5
Reclassification adjustments - contract settlements [$0.2 and ($21.4) pre-tax]	**---**	0.1	(13.1)
Deferred hedging gains (losses) [$1.5 and ($0.2) pre-tax, respectively]	**0.9**	---	(0.1)
Unrealized gain on available-for-sale securities [$0.6 pre-tax]	**0.4**	---	---
Total other comprehensive income (loss), net of tax	**15.9**	(52.3)	(22.0)
Total comprehensive income	**$ 145.7**	$ 38.5	$ 78.6

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

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OGE ENERGY CORP.
CONSOLIDATED STATEMENTS OF CASH FLOWS

Year ended December 31 *(In millions)*	**2003**	2002	2001
CASH FLOWS FROM OPERATING ACTIVITIES			
Net Income	**$ 129.8**	$ 90.8	$ 100.6
Adjustments to reconcile net income to net cash provided from operating activities			
Loss (income) from discontinued operations	**0.4**	(9.8)	(6.7)
Cumulative effect of change in accounting principle	**5.4**	---	---
Depreciation	**176.9**	182.5	172.9
Impairment of assets	**10.2**	50.1	---
Deferred income taxes and investment tax credits, net	**116.3**	33.1	27.1
Gain on sale of assets	**(6.1)**	(1.0)	(0.2)
Ineffectiveness of interest rate swap	---	0.2	1.3
Price risk management assets	**(45.8)**	4.8	(10.1)
Price risk management liabilities	**36.7**	16.4	(24.6)
Other assets	**(6.7)**	(36.8)	(29.2)
Other liabilities	**0.8**	(8.6)	3.8
Change in certain current assets and liabilities			
Accounts receivable, net	**(45.6)**	(83.5)	239.9
Accrued unbilled revenues	**(9.8)**	7.4	13.4
Fuel, materials and supplies inventories	**(54.8)**	(26.5)	125.8
Gas imbalance asset	**(22.3)**	(32.4)	52.4
Fuel clause under recoveries	**10.7**	(14.7)	35.4
Other current assets	**(2.3)**	(1.1)	(2.1)
Accounts payable	**18.5**	108.5	(180.6)
Customers' deposits	**1.0**	12.1	5.8
Accrued taxes	**(1.6)**	(4.8)	(4.2)
Accrued interest	**(1.4)**	(4.2)	(0.4)
Fuel clause over recoveries	**32.4**	(23.4)	23.4
Gas imbalance liability	**(0.3)**	16.3	(63.5)
Other current liabilities	**19.4**	7.9	(6.2)
Net Cash Provided from Operating Activities	**361.8**	283.3	474.0
CASH FLOWS FROM INVESTING ACTIVITIES			
Capital expenditures	**(181.3)**	(234.5)	(211.7)
Proceeds from sale of assets	**16.2**	1.7	0.8
Other investing activities	**1.6**	(0.5)	0.4

Net Cash Used in Investing Activities	**(163.5)**	(233.3)	(210.5)
CASH FLOWS FROM FINANCING ACTIVITIES			
Retirement of long-term debt	**(31.0)**	(140.0)	(11.2)
(Decrease) increase in short-term debt, net	**(72.5)**	126.2	(169.5)
Premium on issuance of common stock	**171.3**	3.1	1.4
Distribution (to) from minority interest	**(2.5)**	--	1.4
Capital lease obligation	---	---	(0.5)
Dividends paid on common stock	**(98.6)**	(99.5)	(103.6)
Net Cash Used in Financing Activities	**(33.3)**	(110.2)	(282.0)
DISCONTINUED OPERATIONS			
Net cash (used in) provided from operating activities	**(1.9)**	17.2	53.9
Net cash provided from (used in) investing activities	**38.1**	51.3	(12.7)
Net cash used in financing activities	---	(1.4)	---
Net Cash Provided from Discontinued Operations	**36.2**	67.1	41.2
NET INCREASE IN CASH AND CASH EQUIVALENTS	**201.2**	6.9	22.7
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	**44.4**	37.5	14.8
CASH AND CASH EQUIVALENTS AT END OF PERIOD	**$ 245.6**	$ 44.4	$ 37.5

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

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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 management of both electricity and natural gas 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 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 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 and trading of natural gas (collectively, Enogex s businesses). Enogex s focus is to utilize its gathering, processing, transportation and storage capacity to execute physical, financial and service transactions to capture revenues across different commodities, locations, or time periods. The vast majority of Enogex s natural gas gathering, processing, transportation and storage assets are located in the major gas producing basins of Oklahoma. Through a 75 percent interest in the NOARK Pipeline System Limited Partnership (NOARK), Enogex also owns a controlling interest in and operates the Ozark Gas Transmission System (Ozark), a FERC regulated interstate pipeline that extends from southeast Oklahoma through Arkansas to southeast Missouri. Enogex was previously engaged in the exploration and production of natural gas, however, this portion of Enogex s business, along with interests in certain gas gathering and processing assets in Texas, were sold in 2002 and in the first quarter of 2003 and are reported in the Consolidated Financial Statements as discontinued operations.

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 Distragas method. The Distragas method is a three-factor formula that uses an equal weighting of payroll, operating income and assets. The Company believes this method provides a reasonable basis for allocating common expenses.

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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 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 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. At December 31, 2003 and 2002, regulatory assets (excluding recoverable take or pay gas charges) of approximately $61.7 million and $78.6 million, respectively, are being amortized and reflected in rates charged to customers over periods of up to 20 years. Recoverable take or pay gas charges are not reflected in rates charged to customers. See Note 17 for a further discussion. At December 31, 2003 and 2002, regulatory liabilities (excluding fuel clause over recoveries) of approximately $116.3 million and $109.3 million, respectively, have been reclassified from Accumulated Depreciation in accordance with SFAS No. 143, Accounting for Asset Retirement Obligations.

OG&E initially records certain costs: (i) that are probable of future recovery as a deferred charge until such time as the cost is approved by a regulatory authority, then the cost is reclassified as a regulatory asset; and (ii) that are probable of future liability as a deferred credit until such time as the amount is approved by a regulatory authority, then the amount is reclassified as a regulatory liability.

The following table is a summary of the Company s regulatory assets and liabilities at December 31:

(In millions)	**2003**	2002
Regulatory Assets		
Recoverable take or pay gas charges	**$ 32.5**	$ 32.5
Income taxes recoverable from customers, net	**31.6**	34.8
Unamortized loss on reacquired debt	**22.1**	23.3
Fuel clause under recoveries	**4.0**	14.7
January 2002 ice storm	**3.6**	5.4
Miscellaneous	**0.4**	0.4
Total Regulatory Assets	**$ 94.2**	$ 111.1
Regulatory Liabilities		
Accrued removal obligations, net	**$ 116.3**	$ 109.3
Fuel clause over recoveries	**32.4**	---
Total Regulatory Liabilities	**$ 148.7**	$ 109.3

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Recoverable take or pay gas charges represent outstanding prepayments of gas related to a reserve for litigation that OG&E is currently involved in which OG&E expects full recovery through its regulatory approved fuel adjustment clause. See Note 17 for a further discussion.

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 the Company 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.

Fuel Clause Under Recoveries are due to under recoveries from OG&E s customers as OG&E s cost of fuel exceeded the amount billed to its customers. Fuel Clause Over Recoveries are due to over recoveries from OG&E s customers as the amount billed to its customers exceeded OG&E s cost of fuel. The Company s fuel recovery clauses are designed to smooth the impact of fuel price volatility on customers bills. As a result, OG&E under recovers fuel cost in periods of rising prices above the baseline charge for fuel and over recovers fuel cost when prices decline below the baseline charge for fuel. Provisions in the fuel clauses allow the Company to amortize under or over recovery.

Accrued removal obligations represent asset retirement costs previously recovered from ratepayers for other than legal obligations. In accordance with SFAS No. 143, the Company was required to reclassify the accrued removal obligations, which had previously been recorded as a liability in Accumulated Depreciation, to a regulatory liability. See Note 2 for a further discussion.

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 liabilities at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the reporting period. Changes to these assumptions and estimates could have a material effect on the Company s consolidated financial statements. In management s opinion, the areas of the Company where the most significant judgment is exercised is in the valuation of pension plan assumptions, impairment estimates, contingency reserves, accrued removal obligations, regulatory assets and liabilities, unbilled revenue for OG&E, the allowance for uncollectible accounts receivable, the valuation of energy

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purchase and sale contracts and natural gas storage inventory and fair value and cash flow hedging policies.

Cash and Cash Equivalents

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

The Company s cash management program utilizes controlled disbursement banking arrangements. Outstanding checks in excess of cash balances were approximately $38.7 million and $44.2 million at December 31, 2003 and 2002, respectively, and are classified as Accounts Payable in the accompanying 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 original due 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 established 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 $4.2 million and $13.6 million at December 31, 2003 and 2002, respectively.

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

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

Fuel Inventories

OG&E

Fuel inventories for the generation of electricity consist of coal, natural gas and oil. These inventories are accounted for under the last-in, first-out (LIFO) cost method. The estimated replacement cost of fuel inventories was higher than the stated LIFO cost by approximately $24.9 million and $7.0 million for 2003 and 2002, respectively, based on the average cost of fuel purchased. The amount of fuel inventory was approximately $60.0 million and $65.4 million at December 31, 2003 and 2002, respectively.

Enogex

Effective January 1, 2003, natural gas storage inventory used in OGE Energy Resources, Inc. s (OERI) business activities are accounted for at the lower of cost or market in accordance with the guidance in Emerging Issues Task Force (EITF) Issue No. 02-3, Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities, which resulted in the rescission of EITF Issue No. 98-10, Accounting for Contracts Involved in Energy Trading and Risk Management Activities, as amended. Prior to January 1, 2003, OERI s inventory was accounted for on a fair value accounting basis utilizing a gas index that in management s opinion approximated the current market value of natural gas in that region as of the Balance Sheet date. On April 1, 2003, natural gas storage inventory used in OERI s business activities began to be accounted for under SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities, as amended. In order to minimize risk, OERI enters into contracts or hedging instruments to hedge the fair value of this inventory. For any contracts that qualify for hedge accounting under SFAS No. 133, the hedged portion of the inventory is recorded at fair value with an offsetting gain or loss recorded currently in earnings. Ineffectiveness associated with OERI s fair value hedge strategy was not material. The fair value of the hedging instrument is also recorded on the books of OERI as a Price Risk Management asset or liability with an offsetting gain or loss recorded in current earnings. At December 31, 2003, OERI had all natural gas inventory hedged with qualified fair value hedges under SFAS No. 133. As part of its recurring business activity, OERI injects and withdraws natural gas under the terms of storage capacity contracts; the amount of natural gas inventory was approximately $82.4 million and $32.9 million at December 31, 2003 and 2002, respectively. See Note 2 for a further discussion.

Effective December 31, 2003, approximately $20.8 million of natural gas storage inventory that was previously classified as Property, Plant and Equipment used in Enogex Inc. s business activities was reclassified to Fuel Inventories on the Consolidated Balance Sheet. During the fourth quarter of 2003, Enogex implemented a business process to actively manage seasonal opportunities around the four billion cubic feet previously reserved to manage pipeline system requirements during peak periods. The intent of management is to capture commercial opportunities while maintaining adequate inventory levels necessary to meet ongoing contractual obligations.

Gas Imbalances

Gas imbalances occur when the actual amounts of natural gas delivered from or received by the Company 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. The Company values all imbalances at average market prices estimated to be in effect at the time the imbalance will be settled. Also, included in Gas Imbalances on the Consolidated Balance Sheets are planned or managed imbalances, referred to as park and loan transactions where gas may be parked or borrowed. Park and loan assets were approximately $45.4 million and $31.1 million, respectively, at December 31, 2003 and 2002 and park and loan liabilities were approximately $9.7 million and $13.5 million, respectively, at December 31, 2003 and 2002.

Property, Plant and Equipment

OG&E

All property, plant and equipment are recorded at cost. Newly constructed plant is added to plant balances at costs which include contracted services, direct labor, materials, overhead and the allowance for funds used during construction (AFUDC). Replacements of major units of property are capitalized as plant. The replaced plant is removed from plant balances and the cost of such property less salvage is charged to Accumulated Depreciation. Repair and replacement of minor items of property are included in the Consolidated Statements of Income as Other Operation and Maintenance Expense. Effective January 1, 2003, removal expense has no longer been charged to Accumulated Depreciation but rather has been charged to regulatory liabilities in accordance with SFAS No. 143.

Enogex

All property, plant and equipment are recorded at cost. Newly constructed plant is added to plant balances at costs which include contracted services, direct labor, materials and overheads used during construction. Replacements of units of property are capitalized as plant. For group assets, the replaced plant is removed from plant balances and charged to Accumulated Depreciation. For non-group assets, the replaced plant is removed from plant balances with the related accumulated depreciation and the remaining balance is recorded as a loss in the Consolidated Statements of Income as Other Expense. Repair and removal costs are included in the Consolidated Statements of Income as Other Operation and Maintenance Expense.

The Company s property, plant and equipment are divided into the following major classes at December 31, 2003 and 2002, respectively. These amounts exclude property, plant and equipment related to discontinued operations.

December 31 *(In millions)*	**2003**	2002
OGE Energy Corp. (holding company)		
Property, plant and equipment	**$ 57.0**	$ 59.6
OGE Energy Corp. property, plant and equipment	**57.0**	59.6
OG&E		
Distribution assets	**1,834.7**	1,749.6
Electric generation assets	**1,614.4**	1,609.5
Transmission assets	**536.9**	520.7
Intangible plant	**5.3**	4.8
Other property and equipment	**265.1**	253.3
OG&E property, plant and equipment	**4,256.4**	4,137.9
Enogex		
Transportation and storage assets	**879.9**	895.5
Gathering and processing assets	**467.4**	462.9
Marketing and trading assets	**7.3**	7.4
Enogex property, plant and equipment	**1,354.6**	1,365.8
Total property, plant and equipment	**$ 5,668.0**	$ 5,563.3

Depreciation

OG&E

The provision for depreciation, which was approximately 2.9 percent of the average depreciable utility plant for 2003 and approximately 3.1 percent of the average depreciable utility plant for 2002, is provided on a straight-line method over the estimated service life of the property. 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.

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 and trading 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 its assets in an effort to ensure a proper economic allocation of resources. The magnitude and timing of any impairment or gain on the disposition of assets that may be identified as not being strategic have not been determined.

Allowance for Funds Used During Construction

AFUDC is calculated according to the FERC pronouncements for the imputed cost of equity and borrowed funds. AFUDC, a non-cash item, is reflected as a credit in the accompanying Consolidated Statements of Income and as a charge to Construction Work in Progress in the accompanying Consolidated Balance Sheets. AFUDC rates, compounded semi-annually, were 1.67 percent, 2.40 percent and 4.87 percent for the years 2003, 2002 and 2001, respectively.

Heat Pump Loans

OG&E has a heat pump loan program, whereby qualifying customers may obtain a loan from OG&E to purchase a heat pump. Customer loans are available for a minimum of $1,500 to a maximum of $13,000 with a term of six months to 84 months. The finance rate is based upon market rates and is reviewed and updated periodically. The interest rates were 11.55 percent and 10.99 percent at December 31, 2003 and 2002, respectively.

OG&E s heat pump loan balance was approximately $1.4 million and $0.5 million at December 31, 2003 and 2002, respectively and is included in Accounts Receivable, Net in the accompanying Consolidated Balance Sheet.

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 estimated each month based on the prior month s activity, current commodity prices, historical seasonal fluctuations and any known adjustments. The estimates are reversed in the following month and customers are billed on actual volumes and contracted prices. Gas sales are calculated on current month nominations and contracted prices. Operating revenues associated with the production of natural gas liquids are estimated based on current month estimated production and contracted prices. These amounts are reversed in the following month and the customers are billed on actual production and contracted prices. Estimated operating revenues are reflected in Accounts Receivable on the Consolidated Balance Sheets and in Operating Revenues on the Consolidated Statements of Income.

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

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 and power marketing 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 and liabilities in the accompanying Consolidated Balance Sheets. See Note 2 for a further discussion.

The default processing fee, which decreases the volatility of Enogex s earnings stream by reducing its exposure to keep whole processing arrangements, is implemented in the event the fractionation spreads (the difference between the price of natural gas liquids extracted and natural gas) are negative. Default processing fees charged to customers will be recorded as deferred revenue until it becomes probable that the gross margin threshold calculated under the terms of the SOC will not be exceeded during 2004. The accounting for default processing fees is not expected to impact full-year earnings, but could affect the timing of those earnings.

Automatic Fuel Adjustment Clauses

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

Stock-Based Compensation

Pursuant to the provisions of SFAS No. 123, Accounting for Stock-Based Compensation, the Company has elected to continue using the intrinsic value method of

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accounting for its stock-based employee compensation plans in accordance with Accounting Principles Board (APB) Opinion No. 25, Accounting for Stock Issued to Employees. Accordingly, the Company has not recognized compensation expense for its stock-based awards to employees. See Note 10 for a further discussion.

The following table reflects pro forma net income and income per average common share had the Company elected to adopt the fair value based method of SFAS No. 123:

	Year Ended December 31		
	2003	2002	2001
	(In millions, except per share data)		
Net income, as reported	**$ 129.8**	$ 90.8	$ 100.6
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	**1.2**	1.1	0.7
Pro forma net income	**$ 128.6**	$ 89.7	$ 99.9
Income per average common share Basic - as reported	**$ 1.59**	$ 1.16	$ 1.29

	Year Ended December 31		
Basic - pro forma	**$ 1.57**	$ 1.15	$ 1.28
Diluted - as reported	**$ 1.58**	$ 1.16	$ 1.29
Diluted - pro forma	**$ 1.57**	$ 1.15	$ 1.28

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, 2003 and 2002 are as follows:

December 31 *(In millions)*	**2003**	2002
Minimum pension liability adjustment, net of tax	**$ (59.7)**	$ (74.3)
Deferred hedging gains, net of tax	**0.9**	---
Unrealized gains on available-for-sale securities, net of tax	**0.4**	---
Total accumulated other comprehensive loss	**$ (58.4)**	$ (74.3)

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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. When a single estimate of the liability cannot be determined, the low end of the estimated range is recorded. Costs are charged to expense or deferred as a regulatory asset based on expected recovery from customers in future rates, if they relate to the remediation of conditions caused by past operations or if they are not expected to mitigate or prevent contamination from future operations. Where environmental expenditures relate to facilities currently in use, such as pollution control equipment, the costs may be capitalized and depreciated over the future service periods. Estimated remediation costs are recorded at undiscounted amounts, independent of any insurance or rate recovery, based on prior experience, assessments and current technology. Accrued obligations are regularly adjusted as environmental assessments and estimates are revised, and remediation efforts proceed. For sites where OG&E has been designated as one of several potentially responsible parties, the amount accrued represents OG&E s estimated share of the cost.

Reclassifications

Certain prior year amounts have been reclassified on the consolidated financial statements to conform to the 2003 presentation.

2. Accounting Pronouncements

In June 2001, the FASB issued SFAS No. 143, which applies to legal obligations associated with the retirement of long-lived assets that result from the acquisition, construction, development and/or the normal operation of a long-lived asset. The scope of SFAS No. 143 includes the Company s accrued plant removal costs for generation, transmission, distribution, processing and pipeline assets. SFAS No. 143 requires that the fair value of a liability for an asset retirement obligation be recognized in the period in which it is incurred if a reasonable estimate of the fair value can be made. If a reasonable estimate of the fair value cannot be made in the period the asset retirement obligation is incurred, the liability shall be recognized when a reasonable estimate of the fair value can be made. Asset retirement obligations associated with long-lived assets included within the scope of SFAS No. 143 are those for which a legal obligation exists under enacted laws, statutes, written or oral contracts, including obligations arising under the doctrine of promissory estoppel. The recognition of an asset retirement obligation is capitalized as part of the carrying amount of the long-lived asset. Asset retirement obligations represent future liabilities and, as a result, accretion expense is accrued on this liability until such time as the obligation is satisfied. Adoption of SFAS No. 143 was required for financial statements issued for fiscal years beginning after June 15, 2002. The Company adopted this new standard effective January 1, 2003 and the adoption of this new standard did not have a material impact on its consolidated financial position or results of operations.

In connection with the adoption of SFAS No. 143, the Company assessed whether it had a legal obligation within the scope of SFAS No. 143. The Company determined that it had a legal obligation to retire certain assets. As the Company currently has no plans to retire any of these assets and the remaining life is indeterminable, an asset retirement obligation was not recognized; however, the Company will monitor these assets and record a liability when a reasonable estimate of the fair value can be made.

SFAS No. 143 also requires that, if the conditions of SFAS No. 71 are met, a regulatory asset or liability should be recorded to recognize differences between asset retirement costs recorded under SFAS No. 143 and legal or other asset retirement costs recognized for ratemaking purposes. Upon the application of SFAS No. 143, all rate regulated entities that are subject to the statement requirements will be required to quantify the amount of previously accumulated asset retirement costs and reclassify those differences as regulatory assets or liabilities. At December 31, 2002, approximately $109.3 million had been previously recovered from ratepayers and recorded as a liability in Accumulated Depreciation related to estimated asset retirement obligations. This balance was reclassified as a regulatory liability on the December 31, 2002 Consolidated Balance Sheet. At December 31, 2003, the regulatory liability for accrued removal obligations, net was approximately $116.3 million.

In July 2002, the FASB issued SFAS No. 146, Accounting for Costs Associated with Exit or Disposal Activities. SFAS No. 146 addresses financial accounting and reporting for costs associated with exit and disposal activities and supersedes EITF Issue No. 94-3, Liability Recognition for Certain Employee Termination Benefits and Other Costs to Exit an Activity (including Certain Costs Incurred in a Restructuring). SFAS No. 146 requires recognition of a liability for a cost associated with an exit or disposal activity when the liability is incurred, as opposed to when the entity commits to an exit plan under EITF 94-3. SFAS No. 146 also establishes that the liability should initially be measured and recorded at fair value. Adoption of SFAS No. 146 was required for exit and disposal activities initiated after December 31, 2002. The Company adopted this new standard effective January 1, 2003 and the adoption of this new standard did not have a material impact on its consolidated financial position or results of operations.

In October 2002, the EITF reached a consensus on certain issues covered in EITF 02-3. One consensus of EITF 02-3 requires that all mark-to-market gains and losses, whether realized or unrealized, on financial derivative contracts as defined in SFAS No. 133 be shown net in the Income Statement for financial statements issued for periods beginning after December 15, 2002, with reclassification required for prior periods presented. The Company adopted this consensus effective January 1, 2003 and the application of this consensus did not have a material impact on its consolidated financial position or results of operations as this consensus supports the Company s historical presentation of financial derivative contracts.

Another consensus reached in EITF 02-3 was to rescind EITF 98-10 effective for fiscal periods beginning after December 15, 2002. Effective October 25, 2002, all new contracts and physical inventories that would have been accounted for under EITF 98-10 were no longer marked to market through earnings unless the contracts met the definition of a derivative under SFAS No. 133. Application of the consensus for energy contracts and inventory that existed on or before October 25, 2002 that remain in effect at the date this consensus was initially applied were recognized as a cumulative effect of a change in accounting principle in accordance with APB Opinion No. 20, Accounting Changes. As a result, only energy contracts that meet the

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definition of a derivative in SFAS No. 133 are carried at fair value. The Company adopted this consensus effective January 1, 2003 resulting in an approximate $9.6 million pre-tax loss ($5.9 million after tax). The loss, which was accounted for as a cumulative effect of a change in accounting principle during the first quarter of 2003, was primarily related to natural gas held in storage for trading purposes. This natural gas held in storage was sold during the first quarter of 2003 resulting in an increase in the gross margin on revenues (gross margin) in excess of the cumulative effect loss described above.

In December 2002, the FASB issued SFAS No. 148, Accounting for Stock-Based Compensation Transition and Disclosure an amendment of FASB Statement No. 123. SFAS No. 148 provides alternative methods of transition for a voluntary change to the fair value based method of accounting for stock-based employee compensation which includes the prospective method, modified prospective method and retroactive restatement method. SFAS No. 148 also amends the disclosure requirements of SFAS No. 123 to require prominent disclosures in both annual and interim financial statements about the method of accounting for stock-based employee compensation and the effect of the method used on reported results. Adoption of the annual disclosure and voluntary transition requirements of SFAS No. 148 is required for annual financial statements issued for fiscal years ending after December 15, 2002. Adoption of the interim disclosure requirements of SFAS No. 148 is required for interim periods beginning after December 15, 2002. Pursuant to the provisions of SFAS No. 123, the Company has elected to continue using the intrinsic value method of accounting for its stock-based employee compensation plans in accordance with APB 25. However, the Company has included the required disclosures under SFAS No. 148 in Note 1. Also, see Note 10 for a further discussion.

In December 2002, the FASB issued Interpretation No. 45, Guarantor s Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others. Interpretation No. 45 requires that at the time a company issues a guarantee, the company must recognize an initial liability for the fair value, or market value, of the obligations it assumes under that guarantee. Interpretation No. 45 is applicable on a prospective basis to guarantees issued or modified after December 31, 2002. The Company adopted this new interpretation effective January 1, 2003 and the adoption of this new interpretation did not have a material impact on its consolidated financial position or results of operations.

In January 2003, the FASB issued Interpretation No. 46, Consolidation of Variable Interest Entities, an interpretation of Accounting Research Bulletin No. 51. Interpretation No. 46 requires the consolidation of entities in which an enterprise absorbs a majority of the entity s expected losses, receives a majority of the entity s expected residual returns, or both, as a result of ownership, contractual or other financial interests in the entity. Currently, entities are generally consolidated by an enterprise when it has a controlling financial interest through ownership of a majority voting interest in the entity.

In October 2003, the FASB issued Interpretation No. 46-6, Effective Date of FASB Interpretation No. 46, Consolidation of Variable Interest Entities, in which the FASB agreed to defer, for public companies, the required effective dates to implement Interpretation No. 46 for interests held in a variable interest entity (VIE) or potential VIE that was created before

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February 1, 2003. For calendar year-end public companies, the deferral effectively moved the required effective date from the third quarter to the fourth quarter of 2003.

As a result of Interpretation No. 46-6, a public entity need not apply the provisions of Interpretation No. 46 to an interest held in a VIE or potential VIE until the end of the first interim or annual period ending after December 15, 2003, if the VIE was created before February 1, 2003 and the public entity has not issued financial statements reporting that VIE in accordance with Interpretation No. 46, other than in the disclosures required by Interpretation No. 46. Interpretation No. 46 may be applied prospectively with a cumulative-effect adjustment as of the date on which it is first applied or by restating previously issued financial statements for one or more years with a cumulative-effect adjustment as of the beginning of the first year restated. The Company adopted this new interpretation effective December 31, 2003 resulting in an approximate $0.8 million pre-tax gain ($0.5 million after tax). The adoption of this new interpretation resulted in the deconsolidation of the trust originated preferred securities of OGE Energy Capital Trust I, a wholly owned financing trust of the Company (see Note 12), and the consolidation of Energy Insurance Bermuda Ltd. (EIB) Mutual Business Program No. 19 (MBP 19).

EIB is incorporated in Bermuda under the Companies Act of 1981, as amended. The Company began participating in EIB through MBP 19 on November 15, 1998. The Company is the sole participant in MBP 19. The Company has issued an $8.0 million standby letter of credit to MBP 19 for the benefit of insuring parts of the Company s property and liability insurance programs. MBP 19 was established to provide $15.0 million worth of property and liability insurance for the Company. The $8.0 million letter of credit was issued to provide protection for MBP 19 in case of large insurance claim losses. At December 31, 2003, there were no drawings against this letter of credit. This letter of credit renews automatically on an annual basis. Since a letter of credit was issued, the total equity investment at risk of MBP 19 is not sufficient to permit it to finance its activities without additional subordinated financial support from other parties. The Company significantly participates in the profits and losses of MBP 19, has the ability to participate significantly by input to EIB through the OGE Advisory Committee as provided by the Participation Agreement executed by the Company and EIB, has sole voting rights and has the obligation to absorb expected losses and the right to receive residual returns. Therefore, since the letter of credit was issued to EIB on behalf of MBP 19, MBP 19 is considered a VIE as defined in Interpretation No. 46 and the Company is the primary beneficiary which resulted in the consolidation of MBP 19 into the Company s Consolidated Financial Statements for the year ended December 31, 2003.

In April 2003, the FASB issued SFAS No. 149, Amendments of Statement 133 on Derivative Instruments and Hedging Activities. SFAS No. 149 amends and clarifies financial accounting and reporting for derivative instruments, including certain instruments embedded in other contracts and for hedging activities under SFAS No. 133. This statement requires that contracts with comparable characteristics be accounted for similarly. In particular, this statement clarifies under what circumstances a contract with an initial net investment meets the characteristic of a derivative, clarifies when a derivative contains a financing component, amends the definition of an underlying hedged risk to conform to language used in Interpretation No. 45 and amends certain other existing pronouncements. This statement, the provisions of which are

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to be applied prospectively, is effective for contracts entered into or modified after June 30, 2003 and for hedging relationships designated after June 30, 2003. The Company adopted this new standard effective July 1, 2003 and the adoption of this new standard did not have a material impact on its consolidated financial position or results of operations.

In May 2003, the FASB issued SFAS No. 150, Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity. SFAS No. 150 establishes standards for how an issuer classifies and measures certain financial instruments with characteristics of both liabilities and equity. The requirements of this statement apply to an issuer s classification and measurement of freestanding financial instruments, including those that comprise more than one option or forward contract. This statement does not apply to features that are embedded in a financial instrument that are not a derivative in its entirety. This statement also addresses questions about the classification of certain financial instruments that embody obligations to issue equity shares. SFAS No. 150 requires that instruments that are redeemable upon liquidation or termination of an issuing subsidiary that has a limited-life are considered mandatorily redeemable shares under SFAS No. 150 in the consolidated financial statements of the parent. Accordingly, these noncontrolling interests are required to be classified as liabilities under SFAS No. 150. All provisions of this statement, except the provisions related to a limited-life subsidiary, are effective for financial instruments entered into or modified after May 31, 2003, and otherwise are effective at the beginning of the first interim period beginning after June 15, 2003. Companies are not required to recognize noncontrolling interests of a limited-life subsidiary as a liability in the consolidated financial statements and should continue to account for these interests as minority interests until the FASB considers resulting implementation issues associated with the measurement and recognition guidance for these noncontrolling interests. Except for the provisions related to a limited-life subsidiary, the Company adopted this new standard effective July 1, 2003 and the adoption of this new standard did not have a material impact on its consolidated financial position or results of operations. The Company does not expect that the provisions related to a limited-life subsidiary will have a material impact on its consolidated financial position or results of operations.

In December 2003, the FASB issued SFAS No. 132 (Revised), Employers Disclosures about Pensions and Other Postretirement Benefits, an amendment of FASB Statements No. 87, 88 and 106. This Statement revised employers disclosures about pension plans and other postretirement benefits. It does not change the measurement or recognition of those plans required by FASB Statements No. 87, Employers Accounting for Pensions, No. 88, Employers Accounting for Settlements and Curtailments of Defined Benefit Pension Plans and for Termination Benefits, and No. 106, Employers Accounting for Postretirement Benefits Other Than Pensions. This Statement requires additional disclosures to those in the original Statement 132, Employers Disclosures about Pensions and Other Postretirement Benefits, for defined benefit pension plans and other defined benefit postretirement plans. Additional disclosures include information describing the types of plan assets, investment strategy, measurement date, plan obligations, cash flows and the components of net periodic benefit cost recognized during interim periods. Adoption of the provisions of this statement, except the provisions related to foreign plans and estimated future benefit payments, is required for financial statements issued for fiscal years ending after December 15, 2003. Adoption of the interim provisions of this statement is required for interim periods beginning after December 15,

2003. Adoption of the provisions of this statement related to foreign plans and estimated future benefit payments is required for financial statements issued for fiscal years ending after June 15, 2004. The Company adopted this new standard effective December 31, 2003 and the adoption of this new standard did not have a material impact on its consolidated financial position or results of operations.

3. Price Risk Management Assets and Liabilities

Non-Trading Activities

The Company periodically utilizes derivative contracts to manage the exposure of its assets to unfavorable changes in commodity prices, as well as to reduce exposure to adverse interest rate fluctuations. During 2003 and 2002, the Company s use of non-trading price risk management instruments involved the use of commodity price and interest rate swap agreements. These agreements involve 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.

In accordance with SFAS No. 133, the Company recognizes all of its derivative instruments as Price Risk Management assets or liabilities in the Balance Sheet at fair value with such amounts classified as current or long-term based on their anticipated settlement. 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 as well as the offsetting gain or loss on the hedged item attributable to the hedged risk are recognized in the same line item associated with the hedged item in current earnings during the period of the change in fair values. 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. Hedge effectiveness is measured at least quarterly based on the relative changes in fair value between the derivative contract and hedged item during the period of hedge designation. 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. Any amounts recorded in Accumulated Other Comprehensive Income will remain in other comprehensive income until such time the forecasted transaction is deemed probable not to occur. The Company s interest rate swap agreements have been designated as fair value hedges and qualified for the shortcut method prescribed by SFAS No. 133. Under the shortcut method, the Company assumes that the hedged item s change in fair value is exactly as much as the derivative s change in fair value.

Based on the Company s derivative positions related to non-trading activity and market prices in effect at January 1, 2001, the adoption of SFAS No. 133 resulted in a reduction to Accumulated Other Comprehensive Income of approximately $26.9 million ($16.5 million after tax). This amount was associated with certain cash flow hedges in place at January 1, 2001 and

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was reclassified into earnings during 2001 as the hedged production was sold. As a result of subsequent changes in market prices, the Company ultimately recognized a $0.8 million loss on the settlement of these contracts during 2001, including a gain of $4.7 million related to the ineffective portion of the change in value of the derivative contracts. At December 31, 2002, the Company had no outstanding cash flow hedges, and no amounts were included in Accumulated Other Comprehensive Loss related to cash flow hedges. At December 31, 2001, the Company had one outstanding cash flow hedge, and approximately a $0.1 million after tax loss was included in Accumulated Other Comprehensive Loss.

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 98-10. Under the guidance provided by 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 accompanying Consolidated Balance Sheets, classified as current or long-term based on their anticipated settlement. Unrealized gains and losses from changes in the market value of open contracts are included in Natural Gas Pipeline Operating Revenues in the Consolidated Statements of Income. Energy trading contracts resulting in delivery of a commodity that meet the requirements of EITF Issue No. 99-19, Reporting Revenues Gross as a Principal or Net as an Agent , are included as sales or purchases in the accompanying Consolidated Statements of Income depending on whether the contract relates to the sale or purchase of the commodity. See Note 2 for a further discussion of the accounting for the Company s energy trading activities.

4. Enogex Discontinued Operations

On March 25, 2002, Enogex entered into an Agreement of Sale and Purchase with West Texas Gas, Inc. to sell all of its interests in Belvan Corp., Belvan Limited Partnership and Todd Ranch Limited Partnership (Belvan) for approximately $9.8 million. The effective date of the sale was January 1, 2002 and the closing occurred on March 28, 2002. The Company recognized approximately a $1.6 million after tax gain related to the sale of these assets.

On August 5, 2002, Enogex entered into an Agreement of Sale and Purchase with Chesapeake Exploration Limited Partnership to sell all of its exploration and production assets located in Oklahoma, Texas, Arkansas and Mississippi for approximately $15.0 million. The effective date of the sale was July 1, 2002 and the closing occurred on September 19, 2002. The Company recognized approximately a $2.3 million after tax loss related to the sale of these assets.

On November 14, 2002, Enogex entered into an Agreement of Sale and Purchase with Quicksilver Resources, Inc. to sell all of its exploration and production assets located in Michigan for approximately $32.0 million. The effective date of the sale was July 1, 2002 and

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the closing occurred on December 2, 2002. The Company recognized approximately a $2.9 million after tax gain related to the sale of these assets.

During the third quarter of 2002, the Company decided to sell all of its interests in the NuStar Joint Venture (NuStar). On January 23, 2003, Enogex entered into an Agreement of Sale and Purchase with Benedum Gas Partners, L.P. to sell all of the interests of its subsidiary, Enogex Products Corporation, in the west Texas properties consisting of NuStar, which has operations consisting of the extraction and sale of natural gas liquids, for approximately $37.0 million. The effective date of the sale was January 1, 2003 and the closing occurred on February 18, 2003. The Company recognized approximately a $1.4 million after tax gain related to the sale of these assets in the first quarter of 2003. The final accounting for the NuStar sale was completed in the third quarter of 2003 which resulted in an additional charge of approximately $0.2 million after tax which was recorded in the third quarter of 2003. The final accounting is subject to approval by all parties to the sale of the joint venture interest.

The Consolidated Financial Statements of the Company have been restated to reflect Enogex s exploration and production assets, NuStar and Belvan, all of which were part of the Natural Gas Pipeline segment, as discontinued operations. Accordingly, revenues, costs and expenses, assets, liabilities and cash flows of the exploration and production assets, NuStar and Belvan have been excluded from the respective captions in the Consolidated Financial Statements and have been reported as Current Assets of Discontinued Operations , Net Property, Plant and Equipment of Discontinued Operations , Deferred Charges and Other Assets of Discontinued Operations , Current Liabilities of Discontinued Operations , Deferred Credits and Other Liabilities of Discontinued Operations , Income from Discontinued Operations and Net Cash Provided from Discontinued Operations. Summarized financial information for the discontinued operations as of December 31 is as follows:

CONSOLIDATED STATEMENTS OF INCOME DATA

(In millions)	**2003**	2002	2001
Operating revenues from discontinued operations	**$ 7.8**	$ 79.5	$ 121.4
Income from discontinued operations before taxes	**1.8**	8.4	6.4

CONSOLIDATED BALANCE SHEET DATA

December 31 *(In millions)*	**2003**	2002
ASSETS		
Accounts receivable, net	**$** ---	$ 4.1
Other	---	0.6
Total current assets of discontinued operations	---	4.7
Plant in service of discontinued operations	---	54.2
Less accumulated depreciation	---	11.4
Net property, plant and equipment of discontinued operations	---	42.8
Total deferred charges and other assets of discontinued operations	---	0.2
Total assets of discontinued operations	**$** ---	$ 47.7
LIABILITIES AND STOCKHOLDER S EQUITY		
Accounts payable	**$** ---	$ 1.1
Accrued taxes	---	0.4
Other	---	0.5
Total current liabilities of discontinued operations	---	2.0
Total deferred credits and other liabilities of discontinued operations	---	9.1
Stockholder s equity	---	36.6
Total liabilities and stockholder s equity of discontinued operations	**$** ---	$ 47.7

5. Asset Disposals

On August 2, 2002, Ozark, in which an Enogex subsidiary owns a 75 percent interest, entered into an Agreement of Sale and Purchase with CenterPoint Energy Gas Transmission Co. to sell approximately 29 miles of transmission lines of the Ozark pipeline located in Pittsburg and Latimer counties in Oklahoma for approximately $10.0 million. On November 18, 2002, the Company received FERC approval for the closing, which occurred on January 6, 2003. The Company recognized approximately a $5.3 million pre-tax gain and approximately $1.1 million in minority interest expense in the first quarter of 2003 related to the sale of these assets, which is recorded in Other Income and Other Expense, respectively, in the accompanying Consolidated Statements of Income. These assets were part of the Natural Gas Pipeline segment.

During the fourth quarter of 2002, the Company recognized a pre-tax impairment loss of approximately $1.8 million in Other Operations related to the Company s aircraft. The impairment resulted from plans to dispose of the aircraft at a price below the carrying amount. The fair value of the aircraft was determined based on a third-party evaluation. The carrying amount of the Company s aircraft was approximately $6.8 million at December 31, 2002. During the second quarter of 2003, the Company recognized a pre-tax impairment loss of $1.0 million related to the Company s aircraft. On July 15, 2003, the Company entered into an Agreement of Sale and Purchase to sell the Company s aircraft for approximately $5.8 million. The closing was completed in August 2003 and the Company recognized approximately a $0.1 million pre-tax loss related to the sale of the aircraft, which is recorded in Other Expense in the accompanying Consolidated Statements of Income.

6. Impairment of Assets

During the fourth quarter of 2002, the Company recognized a pre-tax impairment loss of approximately $48.3 million in the Natural Gas Pipeline segment which related to Enogex natural gas processing and compression assets. In the fourth quarter of 2003, as a result of an ongoing initiative to improve asset utilization in the Natural Gas Pipeline segment, the Company concluded that certain idle Enogex natural gas compression assets may no longer be required to meet the Company s future business needs. As a result, the Company recognized a pre-tax impairment loss of approximately $9.2 million related to these natural gas compression assets. The impairments resulted from plans to dispose of these assets at prices below the carrying amount. The fair value of these assets was determined based on third-party evaluations, prices for similar assets, historical data and projected cash flows. The carrying amount of these assets held for sale was approximately $11.9 million at December 31, 2003. The Company is actively marketing these assets and has developed a plan to sell these assets within one year.

During 2001, the Company recognized a pre-tax impairment loss of approximately $6.0 million in the Natural Gas Pipeline segment which related to certain natural gas processing assets and goodwill held by Belvan. The impairment resulted from plans to dispose of these assets and was determined based on third-party evaluations, prices for similar assets, historical data and projected cash flows. This impairment loss is included in Income from Discontinued Operations in the accompanying Consolidated Statements of Income.

7. 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)*	**2003**	2002	2001
SUPPLEMENTAL CASH FLOW INFORMATION			
Cash Paid During the Period for			
Interest (net of interest capitalized of $0.5, $0.9, $0.7)	**$ 92.6**	$ 109.7	$ 75.9
Income taxes (net of income tax refunds)	**(33.2)**	28.2	30.3
NON-CASH INVESTING AND FINANCING ACTIVITIES			
Change in fair value of long-term debt due to interest rate swaps	**$ (8.3)**	$ 18.3	$ 1.8
Assumption of asset and related debt	---	42.5	---
Issuance of common stock	**11.4**	5.6	---
Change in property, plant and equipment due to transfer of inventory	**20.8**	---	---

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8. Income Taxes

The items comprising income tax expense are as follows:

Year ended December 31 *(In millions)*	**2003**	2002	2001
Provision (Benefit) for Current Income Taxes from Continuing Operations			
Federal	**$ (35.8)**	$ 12.5	$ 22.4
State	**(6.1)**	(0.6)	3.4
Total Provision (Benefit) for Current Income Taxes from Continuing Operations	**(41.9)**	11.9	25.8
Provision for Deferred Income Taxes, net from Continuing Operations			
Federal	**105.3**	31.7	27.2
State	**16.1**	6.6	5.1

Total Provision for Deferred Income Taxes, net from Continuing Operations	**121.4**	38.3	32.3
Deferred Investment Tax Credits, net	**(5.2)**	(5.2)	(5.2)
Income Taxes Relating to Other Income and Deductions	**(0.6)**	(0.4)	---
Total Income Tax Expense from Continuing Operations	**$ 73.7**	$ 44.6	$ 52.9

In connection with the filing in the third quarter of 2003 of the Company s consolidated income tax returns for 2002, the Company elected to change its tax method of accounting related to the capitalization of costs for self-constructed assets to another method prescribed in the Treasury regulations. The accounting method change is for income tax purposes only. For financial accounting purposes, the only change would be recognition of the impact of the cash flow generated by accelerating income tax deductions. This would be 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 all estimated payments made for 2002 have been or will be refunded. As a result of this tax net operating loss, tax credits associated with Enogex s natural gas production were not realized and resulted in approximately $1.8 million in higher income tax expense in discontinued operations. The Company received federal and state income tax refunds of approximately $50.0 million during 2003 related to this tax accounting method change.

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

Year ended December 31	**2003**	2002	2001
Statutory federal tax rate	**35.0%**	35.0%	35.0%
State income taxes, net of federal income tax benefit	**2.8**	2.9	3.3
Tax credits, net	**(2.6)**	(3.8)	(6.2)
Other, net	**0.5**	(1.9)	2.2
Effective income tax rate as reported	**35.7%**	32.2%	34.3%

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

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

The deferred tax provisions, set forth above, are recognized as costs in the ratemaking process by the commissions having jurisdiction over the rates charged by OG&E. The components of Accumulated Deferred Taxes at December 31, 2003 and 2002, respectively, are as follows:

(In millions)	**2003**	2002
Current Accumulated Deferred Tax Assets		
Accrued vacation	**$ 5.8**	$ 6.2
Uncollectible accounts	**1.4**	2.3
Other	**2.2**	2.4
Total Current Accumulated Deferred Tax Assets	**$ 9.4**	$ 10.9
Non-Current Accumulated Deferred Tax Liabilities		
Accelerated depreciation and other property related differences	**$ 710.4**	$ 597.5
Allowance for funds used during construction	**33.1**	35.6
Income taxes refundable to customers	**22.0**	24.4
Company pension plan	**8.9**	---
Bond redemption-unamortized costs	**7.7**	8.1

Total Non-Current Accumulated Deferred Tax Liabilities	**782.1**	665.6
Non-Current Accumulated Deferred Tax Assets		
Deferred investment tax credits	**(12.1)**	(13.8)
Income taxes recoverable from customers	**(9.8)**	(10.9)
Postretirement medical and life insurance benefits	**(6.8)**	(4.4)
Company pension plan	---	(2.8)
Other	**(6.1)**	(6.7)
Total Non-Current Accumulated Deferred Tax Assets	**(34.8)**	(38.6)
Non-Current Accumulated Deferred Income Tax Liabilities, net	**$ 747.3**	$ 627.0

9. Common Stock

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

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In April 2003, the Company filed a Form S-3 Registration Statement to register 7,000,000 shares of the Company s common stock pursuant to the Automatic Dividend Reinvestment and Stock Purchase Plan. Under the terms of this plan, 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 lower discount than that normally incurred in a secondary equity offering. During the year ended December 31, 2003, the Company issued 615,721 shares of common stock at a discount of 1.75 percent and 1,855,989 shares of common stock at a discount of 1.50 percent pursuant to this plan. Also as part of this plan, the Company issued 938,497 shares of common stock and 499,397 shares of common stock at no discount during the years ended December 31, 2003 and 2002, respectively.

For the year ended December 31, 2003 and 2002, respectively, there were 134,098 shares and 10,199 shares of new common stock issued pursuant to the Stock Incentive Plan, which related to exercised stock options.

At December 31, 2003, there were 8,517,976 shares of unissued common stock reserved for the various employee and Company stock plans. Beginning July 30, 2002, the Company issued new common stock to satisfy the common stock requirements of the Company s stock plans rather than purchasing the common stock on the open market. Effective December 1, 2003, the Company began purchasing common stock on the open market to satisfy the common stock requirements of the Company s 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.

10. Stock Incentive Plan

On January 21, 1998, the Company adopted a Stock Incentive Plan (the 1998 Plan). Under this Plan, restricted stock, stock options, stock appreciation rights and performance units may be granted to officers, directors and other key employees. The Company had authorized the issuance of up to 4,000,000 shares under the 1998 Plan.

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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.

Restricted Stock

During 2003 and 2002, no restricted stock was distributed under the Plans. The Company distributed 67,410 shares of restricted common stock under the 1998 Plan during 2001 with a grant date fair value of $21.87 per share. The restricted stock distributed vests at the end of three years. Each share of restricted stock is subject to forfeiture if the recipient ceases to render substantial services to the Company or a subsidiary for any reason other than death, disability or retirement. Awards of restricted stock are subject to an additional condition with all or a portion of the shares of restricted stock being subject to forfeiture based on the Company s return on equity compared to a peer group of companies during the three-year restriction period.

Performance Units

During 2003, the Company awarded 128,469 performance units to certain employees of the Company. These performance units represent the value of one share of the Company s common stock. These performance units are contingently awarded and will be payable in cash or shares of the Company s common stock subject to the condition that the number of performance units, if any, earned by the employees upon the expiration of a three-year award cycle is dependent on the Company s total shareholder return relative to the total shareholder return of a peer group of companies. Each performance unit is subject to forfeiture if the recipient ceases to render substantial services to the Company or a subsidiary for any reason other than death, disability or retirement.

Stock Options

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. The Company has had no expirations of options. Stock option transactions related to the Plans are summarized in the following table:

	2003		2002		2001	
	Number of Options	**Weighted Average Price**	Number of Options	Weighted Average Price	Number of Options	Weighted Average Price
Options Outstanding at beginning of year	**2,419,360**	**$23.4400**	1,570,027	$24.0475	1,190,200	$24.7186
Granted	**838,700**	**16.6850**	959,600	22.2716	428,100	22.5000
Exercised	**(134,098)**	**18.8174**	(10,199)	18.2500	(2,306)	18.2500
Cancelled	**(252,160)**	**24.0963**	(100,068)	22.2988	(45,967)	25.0179
Options Outstanding at end of year	**2,871,802**	**$21.6253**	2,419,360	$23.4400	1,570,027	$24.0475
Options Exercisable at end of year	**1,408,255**	**$24.2019**	1,202,053	$24.8966	799,530	$25.6820

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The fair value of each option grant under the Plans for the years ended December 31, 2003, 2002 and 2001, are estimated on the date of grant using the Black-Scholes option pricing model with the following weighted-average assumptions used for grants in 2003, 2002 and 2001:

	2003	2002	2001
Expected dividend yield	**6.30%**	6.05%	5.70%
Expected price volatility	**22.06%**	22.95%	24.03%
Risk-free interest rate	**3.80%**	4.90%	5.17%
Expected life of options (in years)	**7**	7	7
Weighted-average fair value of options granted	**$ 1.85**	$ 3.10	$ 3.61

The following table provides additional information about stock options outstanding at December 31, 2003:

Range of Exercise Prices	Weighted-Average Remaining Contractual Life	Options Outstanding Number Outstanding	Options Outstanding Weighted-Average Exercise Price	Options Exercisable Number Outstanding	Options Exercisable Weighted-Average Exercise Price
$16.69 - $22.70	7.93 years	2,189,002	$ 19.8742	725,455	$ 21.3429
$25.75 - $28.75	4.22 years	682,800	$ 27.2395	682,800	$ 27.2395

11. Earnings Per Share

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

Year ended December 31 *(In millions)*	**2003**	2002	2001
Average Common Shares Outstanding			
Basic average common shares outstanding	**81.8**	78.1	77.9
Effect of dilutive securities:			
Employee stock options and unvested stock grants	**0.1**	0.1	--
Contingently issuable shares (performance units)	**0.2**	--	--
Diluted average common shares outstanding	**82.1**	78.2	77.9

For the years ended December 31, 2003, 2002 and 2001, respectively, approximately 1.7 million shares, 1.7 million shares and 1.1 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 is anti-dilutive as the exercise price of the stock options exceeded the average common stock market price during the respective period.

12. Trust Originated Preferred Securities

On October 21, 1999, the OGE Energy Capital Trust I, a wholly owned financing trust of the Company, issued $200.0 million principal amount of 8.375 percent trust preferred securities that mature on October 15, 2039. Distributions paid by the financing trust on the trust preferred securities are financed through payments on debt securities issued by the Company and held by the financing trust, which were eliminated in the Company s Consolidated Financial Statements for the years ended December 31, 2002 and 2001. The trust preferred securities are redeemable

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at $25 per share beginning October 15, 2004. Distributions and redemption payments are guaranteed by the Company. Distributions paid to preferred security holders are recorded as Interest Expense on Trust Preferred Securities in the accompanying Consolidated Statements of Income for the years ended December 31, 2002 and 2001. The Company adopted FASB Interpretation No. 46 on December 31, 2003 which resulted in the trust preferred securities being deconsolidated in the Company s Consolidated Financial Statements for the year ended December 31, 2003. As a result of deconsolidating the trust preferred securities, there was a non-cash increase in Other Property and Investments and Long-Term Debt Unconsolidated Affiliate of approximately $6.2 million in the Consolidated Balance Sheet at December 31, 2003. Also, distributions paid to preferred security holders are recorded as Interest Expense Unconsolidated Affiliate in the accompanying Consolidated Statements of Income for the year ended December 31, 2003.

13. Long-Term Debt

A summary of the Company s long-term debt is included in the accompanying Consolidated Statements of Capitalization. OG&E has four series of long-term debt with optional redemption provisions which allow the holders to request repayment of the long-term debt at various dates prior to the maturity. The debt series which are redeemable at the option of the holder during the next 12 months are as follows:

SERIES	**DATE DUE**	**AMOUNT**
6.500 %	Senior Notes, Series Due July 15, 2017	**$ 125.0**
Variable %	Garfield Industrial Authority, January 1, 2025	**47.0**
Variable %	Muskogee Industrial Authority, January 1, 2025	**32.4**

Variable %	Muskogee Industrial Authority, June 1, 2027		**56.0**
	Total	**$**	**260.4**

The 6.500 percent Senior Notes (Senior Notes) will be repayable on July 15, 2004, at the option of the holders, at 100 percent of the principal amount, together with accrued and unpaid interest to July 15, 2004. In order for a Senior Note to be repaid, the Company must receive at the principal corporate trust office of the Senior Note Trustee during the period from and including May 15, 2004 to and including the close of business on June 15, 2004, a Senior Note with the form entitled Option to Elect Repayment on these Senior Notes or other documentation with this information. The repayment option may be exercised by the holder of a Senior Note for less than the entire principal amount of the Senior Note, provided the principal amount is in denominations of $1,000. If the Senior Note holders elect repayment options prior to the maturity, the Company has sufficient liquidity but would seek to refinance these obligations in the capital markets. Such refinancing may incur higher annual interest charges. However, the Company does not believe there is a high probability that repayment of the Senior Notes will be accelerated due to the current and anticipated interest rate environment.

All of the variable rate industrial authority bonds (Bonds) are subject to tender at the option 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

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purchased. The repayment option may only be exercised by the holder of a Bond for the entire principal amount. A third party remarketing agent for the Bonds will attempt to remarket any Bonds tendered for purchase. If the remarketing agent is unable to remarket any such Bonds, the Company is obligated to repurchase such unremarketed Bonds. The Company has sufficient liquidity to meet these obligations. However, the Company does not believe there is a high probability that repayment of the Bonds will be accelerated due to the current and anticipated interest rate environment.

On June 15, 1998, NOARK issued $80.0 million of long-term notes in a private placement. The Company has guaranteed 40 percent of these notes, while the joint partner has guaranteed 60 percent of the notes. The notes mature on June 1, 2018, and require semi-annual principal payments of $1.0 million plus interest at a fixed rate of 7.15 percent with a final balloon payment of $40 million due at maturity. The Company s portion of the semi-annual principal payments is approximately $0.4 million. The joint partner s portion of this long-term debt is included in Non-recourse Debt of Joint Venture on the accompanying Consolidated Balance Sheets. Additionally, during 1998, Enogex issued a note of approximately $5.7 million payable to a former interest owner of NOARK. The note, which matures on July 1, 2020, incurs interest at a fixed rate of 7.00 percent. Principal and interest payments of approximately $0.8 million are due annually beginning July 1, 2004.

During 2003 and 2002, approximately $19.0 million and $113.0 million, respectively, of Enogex s long-term debt matured and approximately $12.0 million and $27.0 million, respectively, was redeemed during 2003 and 2002 which is itemized in the following table.

(In millions)	**2003**	2002
Series Due 2002 -- 7.02% - 8.13%	**$ ---**	$ 113.0
Series Due 2003 -- 6.60% - 8.28%	**19.0**	---
Series Due 2012 -- 8.35% - 8.90%	---	10.0
Series Due 2017 -- 8.96%	---	15.0
Series Due 2018 -- 7.15%	**2.0**	2.0
Series Due 2023 -- 7.75%	**10.0**	---
Total	**$ 31.0**	$ 140.0

Maturities of the Company s long-term debt during the next five years consist of $53.3 million in 2004; $146.5 million in 2005; $2.3 million in 2006; $5.3 million in 2007 and $3.3 million in 2008.

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 Other and the unamortized premium and discount on long-term debt is classified as Long-Term Debt, respectively, in the accompanying Consolidated Balance Sheets and are being amortized over the life of the respective debt. Also, at December 31, 2003, the Company is in compliance with all of its debt agreements.

Interest Rate Swap Agreements

At December 31, 2003 and 2002, the Company had three outstanding interest rate swap agreements: (i) OG&E entered into an interest rate swap agreement, effective March 30, 2001, to

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

At December 31, 2003 and 2002, the fair values pursuant to the interest rate swaps were approximately $7.6 million and $15.9 million, respectively, and are classified as Deferred Charges and Other Assets Price Risk Management in the accompanying Consolidated Balance Sheets. A corresponding net increase of approximately $7.6 million and $15.9 million was reflected in Long-Term Debt at December 31, 2003 and 2002, respectively, as these fair value hedges were effective at December 31, 2003 and 2002.

On April 6, 2001, the Company entered into a one-year interest rate swap agreement to lock in a fixed rate of 4.41 percent, effective April 10, 2001, on $140.0 million of variable rate short-term debt. The objective of this interest rate swap was to achieve a lower cost of debt and to reduce exposure to short-term interest rate volatility associated with the Company s commercial paper program. This interest rate swap initially qualified for hedge accounting treatment as a cash flow hedge under SFAS No. 133. However, due to unexpected changes in the level of commercial paper issued during the third quarter of 2001, hedge accounting treatment under SFAS No. 133 was discontinued as of July 1, 2001, and all subsequent changes in the fair value of the swap were recorded as Interest Expense. During 2002 and 2001, approximately $0.2 million and $1.3 million, respectively, were recorded as Interest Expense in the accompanying Consolidated Statements of Income. At December 31, 2002, no amounts were included in Accumulated Other Comprehensive Loss related to this cash flow hedge. As of December 31, 2001, approximately a $0.1 million after tax loss was included in Accumulated Other Comprehensive Loss related to this cash flow hedge.

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 maximum and average amounts of short-term borrowings during 2003 on a consolidated basis were approximately $279.3 million and $178.4 million, respectively, at a weighted average interest rate of 1.67 percent. The weighted average interest rates for 2002 and 2001 were 2.40 percent and 4.87 percent, respectively.

Consolidated short-term debt of approximately $202.5 million and $275.0 million, respectively, was outstanding at December 31, 2003 and 2002. The following table shows the Company s lines of credit in place and available cash at December 31, 2003. Short-term borrowings are expected to consist of a combination of bank borrowings and commercial paper.

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Lines of Credit and Available Cash *(In millions)*

Entity	Amount Available	Amount Outstanding	Maturity
OGE Energy Corp. (A)	$ 15.0	$ ---	April 6, 2004
OG&E	100.0	---	June 26, 2004
OGE Energy Corp. (A)	300.0	---	December 9, 2004
Total	415.0	---	
Cash	245.6	N/A	N/A
Total	$ 660.6	$ ---	

(A) The lines of credit at OGE Energy Corp. are used to back up the Company s commercial paper borrowings, which were approximately $202.5 million at December 31, 2003. As shown in the table above, on December 11, 2003, the Company renewed its credit facility of $300.0 million maturing on December 9, 2004. This agreement has a one-year term.

The Company s ability to access the commercial paper market could be adversely impacted by a commercial paper ratings downgrade. The lines of credit contain rating grids that require annual fees and borrowing rates to increase if the Company suffers an adverse ratings impact. The impact of additional downgrades of the Company s rating would result in an increase in the cost of short-term borrowings of approximately five to 20 basis points, but would not result in any defaults or accelerations as a result of the rating changes.

Unlike the Company and Enogex, OG&E must obtain regulatory approval from the FERC in order to borrow on a short-term basis. OG&E has the necessary regulatory approvals to incur up to $400 million in short-term borrowings at any one time.

15. Retirement Plans and Postretirement Benefit Plans

Defined Benefit Pension Plan

All eligible employees of the Company are covered by a non-contributory defined benefit pension plan. In early 2000, the Board approved significant changes to the pension plan. Prior to these changes, benefits were 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 that an employee retired and additional significant reductions for retirement prior to age 55. The changes made in 2000 included: (i) elimination of the significant reduction for employees electing to retire before age 55; (ii) the addition of an alternative method of computing the reduction in benefits (based on years of service and age) for an employee retiring prior to age 62, 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; and (iii) the ability of an employee at time of retirement to receive, in lieu of an annuity, a lump sum payment equal to the present value of the annuity. Also, for employees hired after January 31, 2000, the pension plan will be 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 the benefit based on final average compensation as described above.

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It is the Company s policy to fund the plan on a current basis to comply with the minimum required contributions under existing tax regulations. Additional amounts may be contributed from time to time to increase the funded status of the plan. During 2003 and 2002, the Company made contributions of approximately $50.0 million and $48.8 million during 2003 and 2002, respectively, to increase the plan s funded status. Such contributions are intended to provide not only for benefits attributed to service to date, but also for those expected to be earned in the future. During 2004, the Company plans to contribute approximately $56.0 million to the plan. The expected contribution to the pension plan, anticipated to be in the form of cash, is a discretionary contribution and is not required to satisfy the minimum regulatory funding requirements specified by the Employee Retirement Income Security Act of 1974 (ERISA).

During 2003 and 2002, the Company made contributions to the pension plan that exceeded amounts previously recognized as net periodic pension expense and recorded a prepaid benefit obligation at December 31, 2003 and 2002 of approximately $55.7 million and $44.9 million, respectively. At December 31, 2003 and 2002, the Company s projected pension benefit obligation exceeded the fair value of pension plan assets by approximately $131.8 million and $156.7 million, respectively. As a result of recording a prepaid benefit obligation and having a funded status where the projected benefit obligations exceeded the fair value of plan assets, provisions of SFAS No. 87, Employers Accounting for Pensions , required the recognition of an additional minimum liability in the amount of approximately $137.6 million and $163.9 million, respectively, at December 31, 2003 and 2002. 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 2003 or 2002 and did not require a usage of cash and is therefore excluded from the accompanying Consolidated Statements of Cash Flows. The amount recorded as an intangible asset equaled the unrecognized prior service cost with the remainder recorded in Accumulated Other Comprehensive Income. The amount in Accumulated Other Comprehensive Income represents a net periodic pension cost to be recognized in the Consolidated Statements of Income in future periods.

The plan s assets consist primarily of investments in mutual funds, U.S. Government securities, listed common stocks and corporate debt. The following table shows, by major category, the percentage of the fair value of the plan assets held at December 31, 2003 and 2002:

	2003	2002
Equity securities	**61 %**	60 %
Debt securities	**38 %**	39 %
Other securities	**1 %**	1 %
Total	**100 %**	100 %

Investment Policies and Strategies

The plan assets are held in a master trust which follows an investment policy and strategy designed to maximize the long-term investment returns of the master 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 Investment Committee.

The various investment managers used by the master 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 master 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) 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
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	Russell Midcap Index

Small-Cap Equity	Russell 2000 Index
Global Equity	Far East Index

The fixed income manager is expected to use discretion over the asset mix of the master 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. Exposure to

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any single non-government issue is limited to three percent. At least 80 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), Fitch Ratings (Fitch Duff & Phelps LLC. The manager may invest up to 10 percent of the portfolio s market value in cash equivalents (securities with less than six months to maturity). 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. No mortgage derivatives or structured notes are permitted. 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 mid-cap equity portfolio manager focuses on companies with market capitalizations lower than the average company traded on the public exchanges with the following characteristics: price/earnings ratio at or near the Russell Midcap, small dividend yield, return on equity at or near the Russell Midcap and earnings per share growth rate at or near the Russell Midcap. The 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 global equity manager invests primarily in non-dollar denominated equity securities. Investing internationally diversifies the overall master trust across the global equity markets. The managers are 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) are 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 fund 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). A minimum of 95 percent of the total assets must be allocated to the equity markets. 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 or 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.

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Postretirement Benefit Plans

In addition to providing pension benefits, the Company provides certain medical and life insurance benefits for retired members (postretirement benefits). Under the existing plan, employees retiring from the Company on or after attaining age 55 who have met certain length of service requirements were entitled to these postretirement benefits. Pursuant to amendments made to the medical plan in 2000, employees hired prior to February 1, 2000, whose age and years of service total or exceed 80 or have attained age 55 with 10 years of service at the time of retirement are entitled to these postretirement benefits. Employees hired after January 31, 2000, are not entitled to the medical benefits but are entitled to the life insurance 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.

A reconciliation of the funded status of the plans and the amounts included in the accompanying Consolidated Balance Sheets are as follows:

Projected Benefit Obligations

	Pension Plan		Postretirement Benefit Plans	
(In millions)	**2003**	2002	**2003**	2002
Beginning obligations	**$ (443.0)**	$ (402.2)	**$ (183.1)**	$ (120.8)
Service cost	**(15.2)**	(13.3)	**(3.0)**	(2.7)
Interest cost	**(29.2)**	(28.7)	**(10.9)**	(9.6)
Participants contributions	---	---	**(2.2)**	(1.3)
Plan changes	**(4.0)**	(0.3)	---	---
Actuarial gains (losses)	**(43.2)**	(51.9)	**6.6**	(58.9)
Benefits paid	**48.3**	52.6	**11.5**	10.2
Expenses	**0.9**	0.8	---	---
Ending obligations	**$ (485.4)**	$ (443.0)	**$ (181.1)**	$ (183.1)

Fair Value of Plans Assets

	Pension Plan		Postretirement Benefit Plans	
(In millions)	**2003**	2002	**2003**	2002
Beginning fair value	**$ 286.3**	$ 308.7	**$ 46.0**	$ 52.8
Actual return on plans assets	**66.5**	(17.8)	**10.0**	(6.8)
Employer contributions	**50.0**	48.8	**9.3**	8.9
Participants contributions	---	---	**2.2**	1.3
Benefits paid	**(48.3)**	(52.6)	**(11.5)**	(10.2)
Expenses	**(0.9)**	(0.8)	---	---
Ending fair value	**$ 353.6**	$ 286.3	**$ 56.0**	$ 46.0

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Net Periodic Benefit Cost

	Pension Plan			Postretirement Benefit Plans		
(In millions)	**2003**	2002	2001	**2003**	2002	2001
Service cost	**$ 15.2**	$ 13.3	$ 12.0	**$ 3.0**	$ 2.7	$ 2.0
Interest cost	**29.2**	28.7	29.9	**10.9**	9.6	8.3
Return on plan assets	**(24.3)**	(26.9)	(24.7)	**(5.5)**	(5.6)	(5.4)
Amortization of transition obligation	---	---	(1.3)	**2.7**	2.7	2.7
Amortization of net (gain) loss	**13.2**	4.7	0.9	**3.4**	0.5	(0.9)
Amortization of unrecognized prior service cost	**5.8**	5.4	5.5	**2.1**	2.1	2.2
Net periodic benefit cost	**$ 39.1**	$ 25.2	$ 22.3	**$ 16.6**	$ 12.0	$ 8.9

The capitalized portion of the net periodic pension benefit cost was approximately $5.8 million, $4.0 million and $3.5 million at December 31, 2003, 2002 and 2001, respectively. The capitalized portion of the net periodic postretirement benefit cost was approximately $2.6 million,

$2.0 million and $1.5 million at December 31, 2003, 2002 and 2001, respectively.

Funded Status of Plans

	Pension Plan		Postretirement Benefit Plans	
(In millions)	**2003**	2002	**2003**	2002
Funded status of the plans	**$ (131.8)**	$ (156.7)	**$ (125.1)**	$ (137.1)
Unrecognized net (gain) loss	**146.6**	158.9	**65.1**	79.5
Unrecognized prior service cost	**40.9**	42.7	**11.2**	13.2
Unrecognized transition obligation	---	---	**24.7**	27.6
Net amount recognized	**$ 55.7**	$ 44.9	**$ (24.1)**	$ (16.8)

Amounts recognized in the Consolidated Balance Sheets consist of:

	Pension Plan	
(In millions)	**2003**	2002
Prepaid benefit obligation	**$ 55.7**	$ 44.9
Accrued pension and benefit obligations	**(137.6)**	(163.9)
Intangible asset - unamortized prior service cost	**40.2**	42.7
Accumulated deferred tax asset	**37.7**	46.9
Accumulated other comprehensive loss, net of tax	**59.7**	74.3
Net amount recognized	**$ 55.7**	$ 44.9

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Rate Assumptions

	Pension Plan			Postretirement Benefit Plans		
	2003	2002	2001	**2003**	2002	2001
Discount rate	**6.25%**	6.75%	7.25%	**6.25%**	6.75%	7.25%
Rate of return on plans assets	**8.75%**	9.00%	9.00%	**8.75%**	9.00%	9.00%
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	**11.00%**	12.00%	6.00%
Ultimate trend rate	**N/A**	N/A	N/A	**4.50%**	4.50%	4.50%
Ultimate trend year	**N/A**	N/A	N/A	**2010**	2010	2006

N/A - not applicable

The overall expected rate of return on plan assets assumption was decreased from 9.00 percent in 2002 to 8.75 percent in 2003 in determining net periodic pension cost. The rate of return on plan assets assumption is the average long-term rate of earnings expected on the funds currently invested and to be invested for the purpose of providing benefits specified by the pension plan. 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.

Investment Policies and Strategies

The assumed health care cost trend rates have a significant effect on the amounts reported for postretirement medical benefit plans. A one-percentage point change in the assumed health care cost trend rate would have the following effects:

ONE-PERCENTAGE POINT INCREASE

(In millions)	**2003**	2002	2001
Effect on aggregate of the service and interest cost components	**$ 1.9**	$ 1.6	$ 1.2
Effect on accumulated postretirement benefit obligations	**23.1**	23.2	14.0

ONE-PERCENTAGE POINT DECREASE

(In millions)	**2003**	2002	2001
Effect on aggregate of the service and interest cost components	**$ 1.5**	$ 1.3	$ 1.0
Effect on accumulated postretirement benefit obligations	**18.9**	19.0	11.5

On December 8, 2003, President Bush signed into law the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (the Act). The Act expanded Medicare to include, for the first time, coverage for prescription drugs. The Company sponsors retiree medical programs for certain of its locations and the Company expects that this legislation will eventually reduce its costs for some of these programs.

At this point, the Company s investigation into its response to the legislation is preliminary, as we await guidance from various governmental and regulatory agencies concerning the requirements that must be met to obtain these cost reductions as well as the manner in which such savings should be measured. Based on this preliminary analysis, it appears that some of the

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Company s retiree medical plans will need to be changed in order to qualify for beneficial treatment under the Act, while other plans can continue unchanged.

Because of various uncertainties related to the Company s response to this legislation and the appropriate accounting methodology for this event, the Company has elected to defer financial recognition of this legislation until the FASB issues final accounting guidance. When issued, that final guidance could require the Company to change previously reported information. This deferral election is permitted under FASB Staff Position FAS 106-1, Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003.

Defined Contribution Plan

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

Deferred Compensation Plan

The Company provides a deferred compensation plan. The plan s primary purpose is to provide a tax-deferred capital accumulation vehicle for a select group of management, highly compensated employees and non-employee members of the Board of Directors of the Company and to supplement such employees defined contribution plan contributions.

Eligible employees who enroll in the plan may elect to defer up to a maximum of 70 percent of base salary and 100 percent of bonus awards. Eligible directors who enroll in the plan may elect to defer up to a maximum of 100 percent of directors meeting fees and annual

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retainers; however, the Benefits Committee, appointed by the Benefits Oversight Committee (which consists of at least two members appointed by the Board of Directors) may, at its discretion, establish minimum amounts that must be deferred by anyone electing to participate in the plan. In addition, the Compensation Committee of the Board of Directors may authorize employer contributions to participants and the Chief Executive Officer of the Company (with Compensation Committee approval) is authorized to cause the Company to enter into Deferred Compensation Award Agreements with such participants. There were no employer contributions to the plan for the years ended December 31, 2003, 2002 or 2001.

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 and trading of natural gas. Enogex also has been involved in investing in the development for and production of natural gas and crude oil, which investments Enogex sold during 2002. Other Operations for the years ended December 31, 2002 and 2001 primarily includes unallocated corporate expenses, interest expense on commercial paper and the Trust Originated Preferred Securities. As a result of the adoption of FASB Interpretation No. 46 on December 31, 2003, this resulted in the deconsolidation of the Trust Originated Preferred Securities and the consolidation of MBP 19 for the year ended December 31, 2003 in the Company s Consolidated Financial Statements. See Note 2 for a further discussion. Therefore, Other Operations for the year ended December 31, 2003 primarily includes unallocated corporate expenses, interest expense on commercial paper and MBP 19. Intersegment revenues are recorded at prices comparable to those of unaffiliated customers and are affected by regulatory considerations. The following tables are a summary of the results of the Company s business segments for the years ended December 31, 2003, 2002 and 2001.

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2003	Electric Utility	Natural Gas Pipeline (A)	Other Operations	Intersegment	Total
(In millions)					
Operating revenues	**$ 1,517.1**	**$ 2,327.8**	**$ ---**	**$ (65.9)**	**$ 3,779.0**
Fuel	**544.5**	---	---	**(44.7)**	**499.8**
Purchased power	**292.9**	---	---	---	**292.9**
Gas and electricity purchased for resale	---	**2,019.1**	---	**(21.2)**	**1,997.9**
Natural gas purchases - other	---	**55.4**	---	---	**55.4**
Cost of goods sold	**837.4**	**2,074.5**	---	**(65.9)**	**2,846.0**
Gross margin on revenues	**679.7**	**253.3**	---	---	**933.0**
Other operation and maintenance	**294.8**	**91.2**	**(14.3)**	---	**371.7**
Depreciation	**121.8**	**44.2**	**10.9**	---	**176.9**
Impairment of assets	---	**9.2**	**1.0**	---	**10.2**
Taxes other than income	**46.9**	**17.5**	**2.9**	---	**67.3**
Operating income (loss)	**216.2**	**91.2**	**(0.5)**	---	**306.9**
Other income	**0.8**	**6.6**	**0.7**	---	**8.1**
Other expense	**(3.2)**	**(3.0)**	**(2.8)**	---	**(9.0)**
Interest income	**0.6**	**0.9**	**1.7**	**(1.9)**	**1.3**
Interest expense	**(38.8)**	**(39.8)**	**(21.3)**	**1.9**	**(98.0)**

Income tax expense (benefit)	**60.2**	**22.7**	**(9.2)**	---	**73.7**
Income (loss) from continuing operations	**115.4**	**33.2**	**(13.0)**	---	**135.6**
Loss from discontinued operations	---	**(0.4)**	---	---	**(0.4)**
Income (loss) before cumulative effect of change in accounting principle	**115.4**	**32.8**	**(13.0)**	---	**135.2**
Cumulative effect on prior years of change in accounting principle, net of tax	---	**(5.9)**	**0.5**	---	**(5.4)**
Net income (loss)	**$ 115.4**	**$ 26.9**	**$ (12.5)**	**$ ---**	**$ 129.8**
Total assets	**$ 2,775.2**	**$ 1,585.6**	**$ 1,745.2**	**$ (1,521.3)**	**$ 4,584.7**
Capital expenditures	**$ 148.7**	**$ 28.1**	**$ 4.5**	**$ ---**	**$ 181.3**

(A) Beginning with the first quarter of 2002, Natural Gas Pipeline s operations consist of three related businesses: Transportation and Storage, Gathering and Processing and Marketing and Trading. The following table is supplemental Natural Gas Pipeline information.

2003	Transportation and Storage	Gathering and Processing	Marketing and Trading	Eliminations	Total
(In millions)					
Operating revenues	**$ 249.0**	**$ 512.0**	**$ 1,964.0**	**$ (397.2)**	**$ 2,327.8**
Operating income	**$ 64.2**	**$ 14.0**	$ **13.0**	**$ ---**	**$ 91.2**

2002	Electric Utility	Natural Gas Pipeline (A)	Other Operations	Intersegment	Total
(In millions)					
Operating revenues	$ 1,388.0	$ 1,684.0	$ ---	$ (48.1)	$ 3,023.9
Fuel	435.8	---	---	(33.6)	402.2
Purchased power	260.0	---	---	---	260.0
Gas and electricity purchased for resale	---	1,402.1	---	(14.5)	1,387.6
Natural gas purchases - other	---	70.5	---	---	70.5
Cost of goods sold	695.8	1,472.6	---	(48.1)	2,120.3
Gross margin on revenues	692.2	211.4	---	---	903.6
Other operation and maintenance	282.9	101.1	(14.0)	---	370.0
Depreciation	123.1	49.3	10.1	---	182.5
Impairment of assets	---	48.3	1.8	---	50.1
Taxes other than income	47.1	15.7	2.5	---	65.3
Operating income (loss)	239.1	(3.0)	(0.4)	---	235.7
Other income	0.7	1.5	1.5	---	3.7
Other expense	(3.1)	(0.6)	(1.0)	---	(4.7)
Interest income	1.2	1.1	19.1	(19.7)	1.7

Interest expense	(40.2)	(49.7)	(40.6)	19.7	(110.8)
Income tax expense (benefit)	71.6	(19.2)	(7.8)	---	44.6
Income (loss) from continuing operations	126.1	(31.5)	(13.6)	---	81.0
Income from discontinued operations	---	9.8	---	---	9.8
Net income (loss)	$ 126.1	$ (21.7)	$ (13.6)	$ ---	$ 90.8
Total assets	$ 2,659.9	$ 1,532.6	$ 1,820.3	$ (1,747.9)	$ 4,264.9
Capital expenditures	$ 198.7	$ 20.0	$ 14.8	$ 1.0	$ 234.5

(A) Beginning with the first quarter of 2002, Natural Gas Pipeline s operations consist of three related businesses: Transportation and Storage, Gathering and Processing and Marketing and Trading. The following table is supplemental Natural Gas Pipeline information.

2002	Transportation and Storage	Gathering and Processing	Marketing and Trading	Eliminations	Total
(In millions)					
Operating revenues	$ 444.6	$ 179.0	$ 1,350.5	$ (290.1)	$ 1,684.0
Operating income (loss)	$ 45.6	$ (49.5)	$ 0.9	$ ---	$ (3.0)

2001	Electric Utility	Natural Gas Pipeline	Other Operations	Intersegment	Total
(In millions)					
Operating revenues	$ 1,456.8	$ 1,649.8	$ ---	$ (42.2)	$ 3,064.4
Fuel	485.8	---	---	(36.3)	449.5
Purchased power	280.7	---	---	---	280.7
Gas and electricity purchased for resale	---	1,318.4	---	(5.9)	1,312.5
Natural gas purchases - other	---	142.9	---	---	142.9
Cost of goods sold	766.5	1,461.3	---	(42.2)	2,185.6
Gross margin on revenues	690.3	188.5	---	---	878.8
Other operation and maintenance	287.3	93.0	(10.0)	---	370.3
Depreciation	119.8	45.4	7.7	---	172.9
Taxes other than income	46.6	15.7	2.4	---	64.7
Operating income (loss)	236.6	34.4	(0.1)	---	270.9
Other income	1.1	1.9	0.1	---	3.1
Other expense	(3.5)	(0.1)	(0.6)	---	(4.2)
Interest income	2.4	3.2	22.4	(23.8)	4.2
Interest expense	(46.0)	(57.9)	(47.1)	23.8	(127.2)
Income tax expense (benefit)	69.4	(6.8)	(9.7)	---	52.9
Income (loss) from continuing operations	121.2	(11.7)	(15.6)	---	93.9

Income from discontinued operations	---	6.7	---	---	6.7
Net income (loss)	$ 121.2	$ (5.0)	$ (15.6)	$ ---	$ 100.6
Total assets	$ 2,549.8	$ 1,526.7	$ 1,691.8	$ (1,650.3)	$ 4,118.0
Capital expenditures	$ 132.3	$ 70.0	$ 9.4	$ ---	$ 211.7

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17. Commitments and Contingencies

Capital Expenditures

The Company s capital expenditures are estimated at approximately: 2004 $406.2 million, 2005 $244.2 million and 2006 $242.0 million.

Operating Lease Obligations

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

(In millions)	2004	2005	2006	2007	2008	2009 and Beyond
Operating lease obligations						
OG&E railcars	$ 5.4	$ 5.5	$ 5.4	$ 5.5	$ 5.4	$ 30.4
Enogex noncancellable operating leases	3.6	3.5	2.8	1.8	0.5	0.2
Total operating lease obligations	$ 9.0	$ 9.0	$ 8.2	$ 7.3	$ 5.9	$ 30.6

Payments for operating lease obligations were approximately $9.8 million, $10.6 million and $8.2 million in 2003, 2002 and 2001, respectively.

OG&E Railcar Leases

At December 31, 2003, OG&E has noncancellable operating leases which have purchase options covering 1,479 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. At the end of the lease term which is March 31, 2006, OG&E has the option to purchase the railcars at a stipulated fair market value. If OG&E chooses not to purchase the railcars, OG&E has a loss exposure up to approximately $9.0 million related to the fair market value of the railcars to the extent the fair market value is less than 80 percent of the lessor s cost of equipment. 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 four 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

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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.

During 2003, 2002 and 2001, OG&E made total payments to cogenerators of approximately $203.0 million, $227.3 million and $222.5 million, respectively, of which approximately $164.7 million, $192.1 million and $190.7 million, respectively, represented capacity payments. All payments for purchased power, including cogeneration, are included in the Consolidated Statements of Income as Cost of Goods Sold. The future minimum capacity payments under the contracts are approximately: 2004 $152.8 million, 2005 $87.9 million, 2006 $86.4 million, 2007 $84.7 million and 2008 $3.1 million.

Fuel Minimum Purchase Commitments

OG&E purchased necessary fuel supplies of coal and natural gas for its generating units of approximately $157.3 million, $164.1 million and $120.0 million for the years ended December 31, 2003, 2002 and 2001, respectively. OG&E has entered into purchase commitments of necessary fuel supplies of approximately: 2004 $160.8 million, 2005 $170.9 million, 2006 $150.0 million, 2007 $152.6 million, 2008 $155.3 million and 2009 and Beyond $152.4 million.

OG&E acquires some of its natural gas for boiler fuel under a wellhead contract that contains provisions allowing the owner to require prepayments for gas if certain minimum quantities are not taken. At December 31, 2003 and 2002, outstanding prepayments for gas of approximately $32.5 million have been recorded in the Provision for Payments of Take or Pay Gas classified as Deferred Credits and Other Liabilities in the accompanying Consolidated Balance Sheets. The outstanding prepayments of gas relate to a reserve for litigation that OG&E is currently involved in. As OG&E may be required to make these prepayments, offsetting amounts of approximately $32.5 million have been recorded at December 31, 2003 and 2002, respectively, in Recoverable Take or Pay Gas Charges classified as Deferred Charges and Other Assets in the accompanying Consolidated Balance Sheets as OG&E expects full recovery through its regulatory approved fuel adjustment clause.

Natural Gas Units

OG&E utilized a request for bid (RFB) to acquire approximately 42 percent of its projected annual natural gas requirements through approximately April 2004. These contracts are tied to various gas price market indices and most will expire in April 2004. A significant portion of future gas requirements of OG&E will be secured through a new multi-year RFB that was issued in February 2004 with deliveries to begin in April 2004. Additional gas requirements of OG&E will be met with monthly and day-to-day purchases as required.

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

In 1998, Enogex entered into a Storage Lease Agreement (the Agreement) with Central Oklahoma Oil and Gas Corp. (COOG). Under the Agreement, COOG agreed to make certain

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enhancements to the Stuart Storage Facility to increase capacity and deliverability of the facility. In 1999 a dispute arose as to whether the natural gas deliverability for the Stuart Storage Facility was being provided by COOG and these issues were submitted to arbitration in October and November 2001. In July 2002, the Oklahoma District Court affirmed the arbitration award and entered judgment against COOG and in favor of Enogex in the amount of approximately $23.3 million (the Judgment).

On July 24, 2002, Enogex exercised the asset purchase option provided in the Agreement and title to the Stuart Storage Facility was transferred to Enogex on October 24, 2002, effective August 9, 2002 (the date COOG turned over operations of the facility to Enogex). As part of the Agreement, the Company agreed in 1998 to make up to a $12 million secured loan to Natural Gas Storage Corporation (NGSC), an affiliate of COOG (the NGSC Loan). Since June 2002, NGSC has failed and refused to repay the NGSC Loan. As of December 31, 2003, the amount outstanding under the NGSC Loan was approximately $8.0 million plus accrued interest.

On August 12, 2002, the Company received a petition in a legal proceeding filed by COOG and NGSC against the Company and Enogex in Texas. COOG and NGSC stated a claim for declaratory judgment asserting, among other things, that NGSC is not obligated to make payments on the NGSC Loan based on various theories and, that: (1) the Company was obligated to demand Enogex make the requisite payments to the Company; (2) the Company is liable to NGSC for failing to demand the requisite payments from Enogex, or alternatively, NGSC is entitled to a reduction in the amount it owes to the Company; (3) Enogex was and is obligated to make the payments to the Company until the indebtedness of NGSC to the Company is reduced to zero; (4) Enogex is not entitled to set off the Judgment against the lease payments that it originally owed to COOG and now owes to the Company; (5) no event of default has occurred; and (6) under the Agreement, the only remedy Enogex had or has if the Stuart Storage Facility did not perform was to seek a modification of the lease payments based upon COOG s expert s analysis of the performance of the Stuart Storage Facility. COOG and NGSC have also stated claims for breach of contract relating to the same allegations in its claim for declaratory relief and include claims for attorneys fees.

The Company objected to being sued in Texas because the Texas Court does not have proper jurisdiction over the Company. On September 24, 2002, Enogex filed an answer in response to the allegations, asserting, among other things, that the disputed issues have already been properly determined by the Arbitration Panel and the Oklahoma Court and, therefore, this action is improper.

On February 27, 2003, Enogex sent its arbitration demand to plaintiffs (COOG and NGSC) regarding the issues between plaintiffs and Enogex in the Texas action, and Enogex named its arbitrator. On February 28, 2003, Enogex filed a motion to dismiss, or in the alternative, to abate, stay and compel arbitration in the Texas action. By Order dated June 19, 2003, the Court granted Enogex s request for arbitration and ordered COOG/NGSC and Enogex to arbitration on all issues and claims arising under the Agreement and/or the asset purchase option, including all issues overlapping with the loan agreement and related documents. The Texas action is stayed in its entirety pending arbitration. Under the arbitration provisions in the Agreement, a final arbitration decision is to be rendered by June 30, 2004.

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On July 16, 2003, the Company and Enogex served separate complaints on the individual shareholders of COOG and NGSC Enogex Inc. v John C. Thrash, John F. Thrash and Robert R. Voorhees, Jr., Case No. CIV-03-0388-L; and OGE Energy Corp. and Enogex Inc. v John C. Thrash, John F. Thrash and Robert R. Voorhees, Jr., Case No. CIV 03-0389-L both filed in the Western District of Oklahoma Federal Court. The Company and Enogex have each stated claims for (1) fraudulent transfer; (2) imposition of an equitable trust; and (3) breach of fiduciary duty.

The Company intends to continue to vigorously pursue its rights in conjunction with the remaining amount owed under the Judgment, plus interest, and the Company and Enogex seek to recover the amount owed under the NGSC Loan, plus interest.

Natural Gas Measurement Cases

Grynberg On June 15, 1999, the Company was served with plaintiff s complaint, which is a qui tam action under the False Claims Act in the United States District Court, State of Oklahoma by plaintiff Jack J. Grynberg, as individual relator on behalf of the United States Government, alleging: (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, has decided not to intervene in this action.

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

In October 2002, the Court granted the Department of Justice s motion to dismiss certain of Plaintiff s claims and issued an order dismissing Plaintiff s valuation claims against all defendants. Various procedural motions have been filed. Discovery is proceeding on limited jurisdiction issues as ordered by the Court. The deposition of relator Grynberg began in December 2002, and continued during 2003.

The Company intends to vigorously defend this action. Since the case is in the early stages of motions and discovery, the Company is unable to provide an evaluation of the

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likelihood of an unfavorable outcome and an estimate of the amount or range of potential loss to the Company at this time.

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

The Company intends to vigorously defend this action. Since the case is in the early stages of motions and discovery, 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 at this time.

Will Price (Price II) On May 12, 2003, the Plaintiffs (same as those in Price I above) filed a new class action petition (Price II) in the District Court of Stevens County, Kansas, relating to wrongful Btu analysis against natural gas pipeline owners and operators, naming the same defendants as in the amended petition of the Price I case. Two Enogex subsidiaries were served on August 4, 2003. The Plaintiffs seek to represent a class of only royalty owners either from whom the defendants had purchased natural gas or measured natural gas since January 1, 1974 to the present. The class action petition alleges improper analysis of gas heating content. In all other respects, the Price II petition appears to be the same as the amended petition in Price I. Discovery on class certification is proceeding.

The Company intends to vigorously defend this action. Since the case is in the early stages of motions and discovery, 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 at this time.

Farmland Industries

Farmland Industries, Inc. (Farmland) voluntarily filed for Chapter 11 bankruptcy protection from creditors on May 31, 2002. Enogex provided gas transportation and supply services to Farmland, and is an unsecured creditor of Farmland. Enogex filed its Proof of Claim on January 7, 2003, for approximately $5.4 million. In April 2003, Enogex negotiated a settlement and received approximately $1.9 million in May 2003.

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On July 31, 2003, Farmland filed its Disclosure Statement for its Reorganization Plan for approval by the bankruptcy court. According to the Disclosure Statement, Farmland proposes to pay its general unsecured creditors an amount between 60 percent and 82 percent on their pre-petition claims. As a general unsecured creditor of Farmland and pursuant to the terms of the Settlement Agreement referenced above, Enogex s recovery under the proposed distribution would be approximately $0.8 million, which is in addition to the $1.9 million Enogex received in May 2003.

Agreement with Colorado Interstate Gas Company

In December 2002, Enogex entered into an agreement with Colorado Interstate Gas Company (CIG) regarding reservation of capacity on a proposed interstate gas pipeline (the Cheyenne Plains Pipeline). If completed, the Cheyenne Plains Pipeline would provide interstate gas transportation services in the states of Wyoming, Colorado and Kansas with a capacity of 560,000 decatherms/day (Dth/day). Under this agreement, Enogex bid to reserve 60,000 Dth/day of capacity on the proposed pipeline for 10 years and two months. Such reservation would result in Enogex having access to significant additional natural gas supplies in the areas to be served by the proposed pipeline. Subject to regulatory and other approvals, CIG is proposing an in-service date no later than August 31, 2005. Cheyenne Plains continues to seek resolution of various environmental issues associated with the proposed construction of the pipeline, and is in the process of acquiring pipeline, equipment and rights of way for the project.

Guarantees

During the normal course of business, Enogex issues guarantees on behalf of its subsidiaries for the purpose of securing credit for certain business activities. These guarantees are for payment when due of amounts payable by its subsidiaries under various agreements with counterparties. At December 31, 2003, accounts payable supported by guarantees was approximately $65.6 million. Since these guarantees by Enogex represent security for payment of payables obtained in the normal course of its subsidiaries business activities, the Company, on a consolidated basis, does not assume any additional liability as a result of this arrangement.

OGE Energy Corp. has issued a $5.0 million guarantee on behalf of OERI and a $15.0 million guarantee on behalf of Enogex Inc. for the purpose of securing credit for certain business activities. These guarantees are for payment when due of amounts payable by OERI and Enogex Inc. under various agreements with counterparties. In December 2003, the guarantee issued on behalf of Enogex Inc. expired and the guarantee issued on behalf of OERI was increased to $7.0 million, of which there is approximately a $1.9 million outstanding liability balance related to this guarantee at December 31, 2003. Since this guarantee by OGE Energy Corp. represents security for payment of payables obtained in OERI s business activities, the Company, on a consolidated basis, does not assume any additional liability as a result of this arrangement.

The Company has issued an $8.0 million standby letter of credit to MBP 19 for the benefit of insuring parts of the Company s property and liability insurance programs. MBP 19 was established to provide $15.0 million worth of property and liability insurance for the Company. The $8.0 million letter of credit was issued to provide protection for MBP 19 in case

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of large insurance claim losses. At December 31, 2003, there were no drawings against this letter of credit. This letter of credit renews automatically on an annual basis.

At December 31, 2003, 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 $6.7 million of collateral to satisfy its obligation under its financial and physical contracts.

Pending Acquisition of Power Plant

On August 18, 2003, OG&E signed an asset purchase agreement to acquire NRG McClain LLC s 77 percent interest in the 520 megawatt (MW) NRG McClain Station (the McClain Plant). Closing has been delayed pending receipt of FERC approval. The acquisition of this interest in the McClain Plant would clearly constitute an acquisition of electric generation (New Generation) under the agreed settlement of OG&E s rate case (the Settlement Agreement). The purchase price for the interest in the McClain Plant is approximately $159.9 million, subject to adjustment for prepaid gas and property taxes. See Note 18 for a further description of this matter and a description of current proceedings involving a PowerSmith Cogeneration Project, L.P. (PowerSmith) QF contract.

Environmental Laws and Regulations

Approximately $10.5 million of the Company s capital expenditures budgeted for 2004 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 $62.3 million during 2004, compared to approximately $52.7 million utilized in 2003. 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.

In 2003, several pieces of national legislation were either introduced or reintroduced after having failed to pass in 2002. These bills could have required the reduction in emissions of sulfur dioxide (SO2), nitrogen oxide (NOX), carbon dioxide (CO2) and mercury from the electric utility industry. Among the bills was President Bush s Clear Skies proposal. While not addressing CO2, this bill would require significant reductions in SO2, NOX and mercury emissions. As in 2002, none of the proposed legislation became law; however, it is expected that numerous multi-pollutant bills will again be introduced in 2004.

As required by Title IV of the Clean Air Act Amendments of 1990 (CAAA), OG&E completed installation and certification of all required continuous emissions monitors at its generating stations in 1995. Since then, OG&E has submitted emissions data quarterly to the Environmental Protection Agency (EPA) as required by the CAAA. Beginning in 2000, OG&E became subject to more stringent SO2 emission requirements. These lower limits had no

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significant financial impact due to OG&E s earlier decision to burn low sulfur coal. In 2003, OG&E s SO2 emissions were well below the allowable limits.

With respect to the NOX regulations of Title IV of the CAAA, 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 2003 were 0.32 lbs/MMBtu. However, further reductions in NOX emissions could be required if, among other things, legislation is enacted, a study currently being conducted by the state of Oklahoma determines that such NOX emissions are contributing to regional haze and that OG&E s facilities impact the air quality of the Tulsa or Oklahoma City metropolitan areas, or if Oklahoma fails to meet the new fine particulate standards. Any of these scenarios would require significant capital and operating expenditures.

The Oklahoma Department of Environmental Quality s 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, 2003, OG&E had received Title V permits for all but one of its generating stations. Since OG&E submitted all of its permit applications on time it is considered in compliance with the Title V permit program even though all permits have not been issued. Air permit fees for generating stations were approximately $0.6 million in 2003. The fees for 2004 are estimated to be approximately the same as in 2003.

Other potential air regulations have emerged that could impact OG&E. On December 15, 2003, the EPA proposed regulations to limit mercury emissions from coal-fired boilers. This rule is expected to be finalized by early 2005. Earliest compliance by OG&E would be January 2008. Depending upon the final regulations, this could result in significant capital and operating expenditures. In addition, on December 17, 2003, the EPA proposed an interstate air quality rule. This rule is intended to control SO2 and NOX from utility boilers in order to minimize the interstate transport of air pollution. In the proposed rule, the state of Oklahoma is exempt from any reductions. However this could change as the EPA has indicated its intentions to review Oklahoma s impact on other states. If Oklahoma is included in the final rule reductions, this could lead to significant capital and operating expenditures by OG&E.

In 1997, the EPA finalized revisions to the ambient ozone and particulate standards. After a court challenge, which delayed implementation, the EPA has now begun to finalize the implementation process. Based on the most recent monitoring data, Oklahoma s Governor in July of 2003 proposed to the EPA that the entire state be designated attainment with the ozone standard. Later in 2003 the EPA approved Oklahoma s request. However, both Tulsa and Oklahoma City had previously entered into an Early Action Compact with the EPA whereby voluntary measures will be enacted to reduce ozone. In order to ensure that ozone levels remain below the standards, both cities intend to comply with the compact. Minimal impact on OG&E s operations is expected.

The EPA also has issued regulations concerning regional haze. These regulations are intended to protect visibility in national parks and wilderness areas throughout the United States. In Oklahoma, the Wichita Mountains would be 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 the process of determining what, if any, impact emission sources in Oklahoma have on national parks and wilderness areas. If an impact is determined, then significant capital expenditures could be required for both the Sooner and Muskogee generating stations.

While the United States has withdrawn its support of the Kyoto Protocol on global warming, legislation has been considered which would limit CO2 emissions. President Bush supports voluntary reductions by industry. OG&E has joined other utilities in voluntary CO2 sequestration projects through reforestation of land in the southern United States. In addition, OG&E has committed to reduce its CO2 emission rate (lbs. CO2/megawatt-hour) by up to five percent over the next 10 years. However, if legislation is passed requiring mandatory reductions this could have a tremendous impact on OG&E s operations by requiring OG&E to significantly reduce the use of coal as a fuel source.

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 2003, OG&E obtained refunds of approximately $0.5 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.

OG&E has submitted three applications during 2003 to renew its Oklahoma pollution discharge elimination system permits. OG&E anticipates that the renewed permits will continue to allow operational flexibility.

OG&E requested, based on the performance of a site-specific study, that the State agency responsible for the development of water quality standards adjust the in-stream copper criterion at one of its facilities. Adjustment of this criterion should allow the facility to avoid costly treatment and/or facility reconfiguration requirements. The State and the EPA have approved the new in-stream criteria for copper.

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 s original rules on this issue were set-aside in 1977 by the Fourth Circuit U.S. Court of Appeals. In 1993, the EPA announced its plan to develop new rules in part due to a lawsuit filed by the Hudson Riverkeeper. To settle the lawsuit, the EPA signed a court-approved consent decree to develop 316(b) regulations. Final rules for existing utility sources were approved on February 16, 2004. Depending on the analysis of these final 316(b) rules, capital and/or operating costs may increase at some of OG&E s generating facilities.

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

Environmental regulation can increase the cost of planning, design, initial installation and operation of Enogex s facilities. Historically, Enogex s total expenditures for environmental control facilities and for remediation have not been significant in relation to its results of operations or financial condition. The Company believes, however, that it is reasonably likely that the trend in environmental legislation and regulations will continue to be towards stricter standards.

Beginning in 2000, the Company began a process to evaluate, determine and report emissions from its pipeline facilities for compliance with recently promulgated maximum achievable control technology regulations. After evaluating the submitted information, the Oklahoma Department of Environmental Quality, beginning in late 2001, issued notices of violation regarding potential air permitting issues at certain of these reported facilities. Generally, the notices alleged violations relating to potential sources of various emissions, with the majority of the sources relating to glycol dehydrators. The Company has resolved all these matters and, in compliance with consent orders entered between the parties, the Company has taken action to submit or modify permits, install control equipment, modify reporting procedures and pay penalties.

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

Other

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

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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, 2003, 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 order of the OCC authorizing OG&E to reorganize into a subsidiary of the Company contains certain provisions which, among other things, ensure the OCC access to the books and records of the Company and its affiliates relating to transactions with OG&E; require the Company to employ accounting and other procedures and controls to protect against subsidization of non-utility activities by OG&E s customers; and prohibit the Company from pledging OG&E assets or income for affiliate transactions.

2002 Settlement Agreement

On October 11, 2002, OG&E, the OCC Staff, the Oklahoma Attorney General and other interested parties agreed to the Settlement Agreement of OG&E s rate case. The administrative law judge subsequently recommended approval of the Settlement Agreement and on November 22, 2002, the OCC signed a rate order containing the provisions of the Settlement Agreement. The Settlement Agreement provides 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 New Generation of not less than 400 MWs to be integrated into OG&E s generation system; and (iv) recovery by OG&E, over three years, of the $5.4 million in deferred operating costs, associated with the January 2002 ice storm, through OG&E s rider for sales to other utilities and power marketers (off-system sales). Previously, OG&E had a 50/50 sharing mechanism in Oklahoma for any off-system sales. The Settlement

Agreement provided that the first $1.8 million in annual net profits from OG&E s off-system sales will go to OG&E, the next $3.6 million in annual net profits from off-system sales will go to OG&E s Oklahoma customers, and any net profits of 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. If any of the $5.4 million is not recovered at the end of the three years, the OCC will authorize the recovery of any remaining costs.

Pending Acquisition of Power Plant

As part of the 2002 Settlement Agreement with the OCC, OG&E undertook to acquire New Generation of not less than 400 MWs. The acquisition of a 77 percent interest in the McClain Plant would clearly constitute an acquisition of such New Generation under the Settlement Agreement. OG&E expects this New Generation, including the interim purchase

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power agreement, will provide savings, over a three-year period, in excess of $75.0 million to its Oklahoma customers. These savings will be derived from: (i) the avoidance of purchase power contracts otherwise needed; (ii) replacing an above market cogeneration contract with PowerSmith when it can be terminated at the end of August 2004; and (iii) fuel savings associated with operating efficiencies of the new plant. These savings, while providing real savings to Oklahoma customers, are not expected to affect the profitability of OG&E because OG&E s rates would not need to be reduced to accomplish these savings. As indicated in the Settlement Agreement, OG&E is required to provide monthly reports, for a period of 36 months after the acquisition, to the OCC Staff, documenting and providing proof of savings experienced by OG&E s 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 have an obligation to credit its Oklahoma customers any unrealized savings below $75.0 million as determined at the end of the 36-month period, which shall be no later than December 31, 2006. PowerSmith has filed an application with the OCC seeking to compel OG&E to continue purchasing power from PowerSmith s qualified cogeneration facility under PURPA at a price that would include an avoided capacity charge equal to the lesser of (i) the rate currently specified in the power purchase agreement between OG&E and PowerSmith or (ii) the avoided cost of the McClain Plant. OG&E does not believe that this matter should be heard at the OCC at this time and that the avoided cost requested by PowerSmith is too high. In the event PowerSmith is ultimately successful and OG&E is required to sign a purchase power agreement, it could negatively affect OG&E s ability to achieve the targeted $75 million three-year customer savings under the existing terms of the Settlement Agreement. PowerSmith and OG&E have been holding discussions to determine if mutually agreeable terms can be reached for a power contract between the companies providing for capacity payments to the PowerSmith facility.

In the event OG&E did not acquire the New Generation by December 31, 2003, the Settlement Agreement requires OG&E to 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. However, if OG&E purchases the New Generation subsequent to January 1, 2004, the credit to Oklahoma customers will terminate in the first month that the New Generation begins initial operations and any previously-credited amounts to Oklahoma customers will be deducted in the determination of the $75.0 million targeted savings.

On August 18, 2003, OG&E signed an asset purchase agreement to acquire NRG McClain LLC s 77 percent interest in the McClain Plant. The acquisition of this interest in the McClain Plant would clearly constitute an acquisition of New Generation under the Settlement Agreement. The purchase price for the interest in the McClain Plant is approximately $159.9 million, subject to adjustment for prepaid gas and property taxes. The McClain Plant includes natural gas-fired combined cycle combustion turbine units and is located near Newcastle, Oklahoma in McClain County, Oklahoma. The McClain Plant began operating in 2001. The owner of the remaining 23 percent in the McClain Plant is the Oklahoma Municipal Power Authority (OMPA).

Closing is subject to customary conditions including receipt of regulatory approval by the FERC. The asset purchase agreement, as amended, provides that, unless extended, either party

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has the right to terminate the contract if the closing does not occur on or before March 16, 2004. Because the current owner of the McClain Plant has filed for bankruptcy protection, the acquisition also was subject to approval by the bankruptcy court. As part of the bankruptcy approval process, NRG McClain LLC s interest in the plant was subject to an auction process and on October 28, 2003, the bankruptcy court approved the sale of NRG McClain LLC s interest in the plant to OG&E. Several parties have filed interventions at the FERC opposing OG&E s application under Section 203 of the Federal Power Act to acquire NRG McClain s interest in the power plant or, alternatively, requesting the FERC to delay approving such acquisition. OG&E believed that its application met the standards under Section 203 set forth by the FERC and that its application would be approved. On December 18, 2003, the FERC shifted its policy regarding market power issues, raised wholesale market power concerns and ordered a hearing regarding OG&E s acquisition of the McClain Plant. The FERC action did not reject OG&E s request to purchase the McClain Plant, but demonstrated that OG&E must address certain issues. On January 20, 2004, OG&E filed a petition for re-hearing of the FERC s December 18, 2003 order which included new mitigation measures that were designed to allow for prompt approval of the transaction. That request is still pending before the FERC. OG&E has no indication whether the FERC will accept those proposed mitigation measures. On March 2, 2004, OG&E filed testimony and exhibits with the FERC administrative law judge. The testimony and exhibits indicate that, if the case proceeds to hearing, the wholesale market power issues that the FERC raised in the December 18, 2003 order may be resolved by the minimal mitigation measures.

Assuming the acquisition occurs, OG&E expects to operate the plant in accordance with a joint ownership and operating agreement with the OMPA. Under this agreement, OG&E would operate the facility, and OG&E and the OMPA would be entitled to the net available output of the plant based on their respective ownership percentages. All fixed and variable costs, except fuel and gas transportation costs, would be shared in proportion to the respective ownership interests. Fuel and gas transportation costs would be shared based on consumption. OG&E expects to utilize its portion of the output, 400 MWs, to serve its native load. As provided in the Settlement Agreement, pending approval of a request to increase base rates to recover the investment in the plant, OG&E will have the right to accrue a regulatory asset, for a period not to exceed 12 months subsequent to the acquisition, consisting of the non-fuel operation and maintenance expenses, depreciation, cost of debt associated with the investment and ad valorem taxes. Upon approval by the OCC of OG&E s request, all prudently incurred costs accrued through the regulatory asset within the 12-month period will be included in OG&E s prospective cost of service.

Despite the delay at the FERC, an agreement to purchase power from the McClain Plant is enabling OG&E to honor the customer savings as outlined in the Settlement Agreement. On January 8, 2004, OG&E filed an application with the OCC and requested that the OCC confirm the steps that OG&E has taken to comply with the Settlement Agreement will result in customer savings being delivered beginning January 1, 2004, and that no further rate reduction is necessary. Various parties have intervened opposing OG&E s request. If the OCC does not agree with OG&E s request, OG&E will be required to reduce electric rates to its Oklahoma customers by approximately $2.1 million per month and would expect to reduce expenditures for

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planned electric system reliability upgrades. The OCC has scheduled a hearing on April 19, 2004 for action in this case.

Assuming that OG&E acquires the McClain Plant, OG&E expects to fund the acquisition with a combination of a capital contribution from the Company, funded in part by the Company s equity issuance in 2003, and the issuance of long-term debt by OG&E.

2003 Rate Case

On September 15, 2003, OG&E filed with the OCC a notice of intent to seek an annual increase in its rates to its Oklahoma customers of more than one percent. The notice listed the following, among others, as major issues to be addressed in its application: (i) the acquisition of New Generation in accordance with the Settlement Agreement; (ii) increased capital expenditures for efficiency improvements and reliability enhancements to ensure fuel costs are minimized; and (iii) increased pension, medical and insurance costs. On October 31, 2003, OG&E filed a request with the OCC to increase its rates by approximately $91 million annually. The increase was intended to pay for its pending acquisition of a 77 percent interest in the McClain Plant, allow for investment in electric system reliability and address rising business costs. The rate plan would have reduced rates for schools and more than 80,000 small businesses and non-profit organizations. On January 15, 2004, OG&E filed an application to withdraw its request for a $91 million rate increase due to the delay at FERC in receiving the necessary approvals to complete the acquisition of the McClain Plant, which was a significant part of this rate case. An order dismissing the case was issued by the OCC on January 30, 2004. On December 18, 2003, the FERC issued an order setting for hearing OG&E s proposed acquisition of the McClain Plant and on January 15, 2004, the FERC administrative law judge in charge of the hearing and the parties to the case agreed to a procedural schedule that would produce a decision on the McClain Plant acquisition no sooner than the third quarter of 2004. OG&E expects to file another rate case in the near future to recover increased operating and capital expenditures.

Gas Transportation and Storage Agreement

As part of the Settlement Agreement, OG&E also agreed to consider competitive bidding for gas transportation service to its natural gas-fired generation facilities pursuant to the terms set forth in the Settlement Agreement. OG&E believes that in order for it to achieve maximum coal generation and ensure reliable electric service, it must have firm no-notice load following service for both gas transportation and gas storage. This type of service is required to satisfy the daily swings in customer demand placed on OG&E s system and still permit natural gas units to not impede coal energy production. OG&E also believes that gas storage is an integral part of providing gas supply to OG&E s generation facilities. Accordingly, OG&E evaluated its competitive bid options in light of these circumstances. OG&E s evaluation clearly demonstrates that the Enogex integrated gas system provides superior firm no-notice load following service to OG&E that is not available from other companies serving the OG&E marketplace. On April 29, 2003, OG&E filed an application with the OCC in which OG&E advised the OCC that, after careful consideration, competitive bidding for gas transportation was rejected in favor of a new intrastate firm no-notice load following gas transportation and storage

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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. During 2003, OG&E paid Enogex approximately $44.7 million for gas transportation and storage services. Based upon requests for information from intervenors, OG&E has requested from Enogex and Enogex has agreed to retain a cost of service consultant to assist in the preparation of testimony related to this case. On January 30, 2004, the OCC issued a procedural schedule for this case. A hearing is scheduled August 10-11, 2004 and an OCC order in the case is expected by the end of 2004. OG&E believes the amount currently paid to Enogex for no-notice load following transportation and storage services is fair, just and reasonable. If any amounts paid by OG&E are found not to be recoverable. OG&E believes such amount would not be material.

Security Enhancements

On April 8, 2002, OG&E filed a joint application with the OCC requesting approval for security investments and a rider to recover these costs from the ratepayers. On August 14, 2002, OG&E filed testimony with the OCC outlining proposed expenditures and related actions for security enhancement and a proposed recovery rider. Attempting to make security investments at the proper level, OG&E has developed a set of guidelines intended to minimize long-term or widespread outages, minimize the impact on critical national defense and related customers, maximize the ability to respond to and recover from an attack, minimize the financial impact on OG&E that might be caused by an attack and accomplish these efforts with minimal impact on ratepayers. The OCC Staff retained a security expert to review the report filed by OG&E. OG&E currently expects that hearings will be held in early 2004.

On October 17, 2003, the OCC filed a notice of inquiry to consider the issues related to the role of the OCC and Oklahoma regulated companies in addressing the security of the electrical system infrastructure and key assets. On March 4, 2004, the OCC deliberated the notice of inquiry and directed the OCC Staff to file a rulemaking proceeding for each utility industry regarding security of the electrical system infrastructure and key assets.

Other Regulatory Actions

The Settlement Agreement, when it became effective, provided for the termination of the Acquisition Premium Credit Rider (APC Rider) and the Gas Transportation Adjustment Credit Rider (GTAC Rider).

The APC Rider was approved by the OCC in March 2000 and was implemented by OG&E to reflect the completion of the recovery of the amortization premium paid by OG&E when it acquired Enogex in 1986. The effect of the APC Rider was to remove approximately $10.7 million annually from the amount being recovered by OG&E from its Oklahoma customers in current rates.

In June 2001, the OCC approved a stipulation (the Stipulation) to the competitive bid process of OG&E s gas transportation service from Enogex. The Stipulation directed OG&E to reduce its rates to its Oklahoma retail customers by approximately $2.7 million per year through the implementation of the GTAC Rider. The GTAC Rider was a credit for gas transportation

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cost recovery and was applicable to and became part of each Oklahoma retail rate schedule to which OG&E s automatic fuel adjustment clause applies. As discussed above, the Settlement Agreement terminated the GTAC Rider. Consequently, these charges for gas transportation provided by Enogex are now included in base rates.

OG&E s Generation Efficiency Performance Rider (GEP Rider) expired in June 2002. The GEP Rider was established initially in 1997 in connection with OG&E s 1996 general rate review and was intended to encourage OG&E to lower its fuel costs by: (i) allowing OG&E to collect one-third of the amount by which its fuel costs were below a specified percentage (96.261 percent) of the average fuel costs of certain other investor-owned utilities in the region; and (ii) disallowing the collection of one-third of the amount by which its fuel costs exceeded a specified percentage (103.739 percent) of the average fuel costs of other investor-owned utilities. In June 2000 the OCC made modifications to the GEP Rider which had the effect of reducing the amount OG&E could recover under the GEP Rider by: (i) changing OG&E s peer group to include utilities with a higher coal-to-gas generation mix; (ii) reducing the amount of fuel costs that can be recovered if OG&E s costs exceed the new peer group by changing the percentage above which OG&E will not be allowed to recover one-third of the fuel costs from Oklahoma customers from 103.739 percent to 101.0 percent; (iii) reducing OG&E s share of cost savings as compared to its new peer group from 33 percent to 30 percent; and (iv) limiting to $10.0 million the amount of any awards paid to OG&E or penalties charged to OG&E. For the period between January 1, 2002 and June 30, 2002, OG&E recovered approximately $2.4 million under the GEP Rider.

FERC Section 311 Rate Case

In December 2001, Enogex made its filing at the FERC under Section 311 of the Natural Gas Policy Act to establish rates and a default processing fee and to address various other issues for the combined Enogex and Transok L.L.C. pipeline systems. By order dated May 9, 2003, the FERC accepted the stipulation and settlement agreement and entered its order modifying Enogex s Statement of Operating Conditions (SOC). The FERC Order required Enogex to modify its SOC to eliminate the priority for scheduling and curtailment purposes for interruptible dedicated gas customers. In June 2003, Apache Corporation (Apache) and the Oklahoma Independent Petroleum Association (OIPA) sought rehearing as to the elimination of the priority for dedicated gas. The FERC issued a tolling order on July 9, 2003, and by order dated January 30, 2004, the FERC denied the Apache and OIPA requests for rehearing and affirmed its May 9 order. The time for judicial appeal of the January 30, 2004 order has not yet expired. The settlement included a fee to be assessed under certain market conditions to process customer gas gathered behind processing plants so that it meets pipeline gas quality Btu standards and can be redelivered to interstate pipelines (default processing fee). The default processing fee, which decreases the volatility of its earnings stream by reducing its exposure to keep whole processing arrangements, is implemented in the event the fractionation spreads (the difference between the price of natural gas liquids extracted and natural gas) are negative. The settlement also approved a monthly low flow meter charge of $200 (offset in any month by the transportation revenues generated by gas through the meter). Pursuant to Enogex s SOC, if Enogex s annual processing gross margin exceeds a specified threshold, Enogex is required to record a default processing fee refund obligation in an amount equal to the lesser of the default processing fees and the amount

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of the processing margin in excess of the specified threshold. During the third and fourth quarters of 2003, the Company established approximately a $4.9 million reserve, based on projected future market conditions, to cover such refund obligations. For the year ended December 31, 2003, the Company has recognized revenue, net of the $4.9 million reserve, of approximately $0.3 million for default processing fees and approximately $0.7 million of low flow meter charges. For 2004, Enogex s forecasted processing gross margin exceeds the threshold calculated under the terms of the SOC. As a result, any default processing fees charged to customers will be recorded as deferred revenue until it becomes probable that the gross margin threshold in the SOC will not be exceeded during 2004. The accounting for default processing fees is not expected to impact full-year earnings, but could affect the timing of those earnings.

State Restructuring Initiatives

Oklahoma

As previously reported, the Electric Restructuring Act of 1997 (the 1997 Act) was initially designed to provide retail customers in Oklahoma a choice of their electric supplier by July 1, 2002. Additional implementing legislation was to be adopted by the Oklahoma Legislature to address many specific issues associated with the 1997 Act and with deregulation. In May 2000, a bill addressing the specific issues of deregulation was passed in the Oklahoma State Senate and then was defeated in the Oklahoma House of Representatives. In May 2001, the Oklahoma Legislature postponed the scheduled start date for customer choice from July 1, 2002 until at least 2003. In addition to postponing the date for customer choice, this legislation called for a nine-member task force to further study the issues surrounding deregulation. The task force includes the Governor or his designee, the Oklahoma Attorney General, the OCC Chair and several legislative leaders, among others. In the 2003 legislative session, additional legislation was introduced to repeal the 1997 Act, but the 2003 legislative session ended without any further action to repeal the 1997 Act. It is unknown at this time whether the 1997 Act will be repealed. The Company will continue to actively participate in the legislative process and expects to remain a competitive supplier of electricity. As a result of the failures of California s attempt to deregulate its electricity markets, the Enron bankruptcy, and associated impacts on the industry, efforts to restructure the electricity market in Oklahoma appear at this time to be delayed indefinitely.

Arkansas

In April 1999, Arkansas passed a law (the Restructuring Law) calling for restructuring of the electric utility industry at the retail level. The Restructuring Law initially targeted customer choice of electricity providers by January 1, 2002. In February 2001, the Restructuring Law was amended to delay the start date of customer choice of electric providers in Arkansas until October 1, 2003, with the APSC having discretion to further delay implementation to October 1, 2005. In March 2003, the Restructuring Law was repealed. As part of the repeal legislation, electric public utilities are permitted to recover transition costs. OG&E incurred approximately $2.4 million in transition costs necessary to carry out its responsibilities associated with efforts to implement retail open access. On January 20, 2004, the APSC issued

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an order which authorized OG&E to recover approximately $1.9 million in transition costs over an 18-month period beginning February 2004.

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:

	2003		2002	
(In millions)	**Carrying Amount**	**Fair Value**	Carrying Amount	Fair Value

Price Risk Management Assets				
Energy Trading Contracts	**$ 67.2**	**$ 67.2**	$ 21.4	$ 21.4
Interest Rate Swaps	**7.6**	**7.6**	15.9	15.9
Price Risk Management Liabilities				
Energy Trading Contracts	**$ 51.4**	**$ 51.4**	$ 14.6	$ 14.6
Long-Term Debt and Preferred Securities				
Senior Notes	**$ 571.8**	**$ 611.8**	$ 575.1	$ 617.2
Industrial Authority Bonds	**135.4**	**135.4**	135.4	135.4
Enogex Notes	**576.0**	**674.7**	612.4	719.0
Trust Originated Preferred Securities	---	---	200.0	213.2
Unconsolidated Affiliate	**206.2**	**217.8**	---	---

The carrying value of the financial instruments on the accompanying 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 and preferred securities is based on quoted market prices and management s estimate of current rates available for similar issues with similar maturities.

20. Subsequent Event (Unaudited)

Sooner Power Plant Coal Dust Explosion

On February 16, 2004, there was a coal dust explosion at OG&E s Sooner Power Plant which caused structural and electrical damage to the coal train unloading system. The generation capacity of the Sooner Plant facility has not been impacted by this incident. The estimated damage costs are between approximately $3.0 million and $4.0 million. The Company expects that the coal train unloading system will be ready to unload coal trains by April 2, 2004. In the meantime, Sooner Power Plant continues to generate power by using coal from the storage pile. The Company is self-insured for this loss.

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REPORT OF INDEPENDENT AUDITORS

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, 2003 and 2002, 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, 2003. 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 auditing standards generally accepted in the 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, 2003 and 2002, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2003, in conformity with accounting principles generally accepted in the United States. 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.

As discussed in Note 2 to the consolidated financial statements, effective January 1, 2003, the Company adopted 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.

/s/ Ernst & Young LLP
Ernst & Young LLP

Oklahoma City, Oklahoma
January 30, 2004

REPORT OF MANAGEMENT

To Our Stockholders:

The management of the Company is responsible for the preparation, integrity and objectivity of the consolidated financial statements of the Company and its subsidiaries and other information included in this report. The consolidated financial statements have been prepared in conformity with accounting principles generally accepted in the United States. As appropriate, the statements include amounts based on informed estimates and judgments of management.

The management of the Company has established and maintains a system of internal control designed to provide reasonable assurance, on a cost-effective basis, that assets are safeguarded, transactions are executed in accordance with management s authorization and financial records are reliable for preparing consolidated financial statements. Management believes that the system of control provides reasonable assurance that errors or irregularities that could be material to the consolidated financial statements are prevented or would be detected within a timely period. Key elements of this system include the effective communication of established written policies and procedures, selection and training of qualified personnel and organizational arrangements that provide an appropriate division of responsibility. This system of control is augmented by an ongoing internal audit program designed to evaluate its adequacy and effectiveness. Management considers the recommendations of the internal auditors and independent auditors concerning the Company s system of internal control and takes timely and appropriate actions to alleviate their concerns. Management believes that as of December 31, 2003, the Company s system of internal control was adequate to accomplish the objectives discussed herein.

The Board of Directors of the Company addresses its oversight responsibility for the consolidated financial statements through its Audit Committee, which is composed of directors who are not employees of the Company. The Audit Committee meets regularly with the Company s management, internal auditors and independent auditors to review matters relating to financial reporting, auditing and internal control. To ensure auditor independence, both the internal auditors and independent auditors have full and free access to the Audit Committee.

The independent public accounting firm of Ernst & Young LLP is engaged to audit, in accordance with auditing standards generally accepted in the United States, the consolidated financial statements of the Company and its subsidiaries and to issue their report thereon.

/s/ Steven E. Moore

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

/s/ Al M. Strecker

Al M. Strecker, Executive Vice President
and Chief Operating Officer

/s/ Peter B. Delaney

Peter B. Delaney, Executive Vice President,
Finance and Strategic Planning - OGE
Energy Corp. and Chief Executive
Officer - Enogex Inc.

/s/ James R. Hatfield

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

/s/ Donald R. Rowlett

Donald R. Rowlett, Vice President
and Controller

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 for a fair statement of the consolidated results of operations for such periods:

Quarter ended *(In millions, except per share data)*		Dec 31	Sep 30	Jun 30	Mar 31
Operating revenues (A) (B)	**2003**	**$ 816.2**	**$ 1,060.0**	**$ 852.6**	**$ 1,050.2**
	2002	829.9	887.3	730.8	575.9
Operating income (loss) (A) (C) (D)	**2003**	**$ 15.3**	**$ 187.3**	**$ 76.6**	**$ 27.7**
	2002	(29.4)	185.9	64.1	15.1
Net income (loss) (C) (D)	**2003**	**$ (1.6)**	**$ 99.5**	**$ 32.2**	**$ (0.3)**
	2002	(30.4)	99.0	28.4	(6.2)
Basic earnings (loss) per average common share	**2003**	**$ (0.03)**	**$ 1.21**	**$ 0.41**	**$ ---**
	2002	(0.39)	1.27	0.36	(0.08)
Diluted earnings (loss) per average common share	**2003**	**$ (0.03)**	**$ 1.20**	**$ 0.41**	**$ ---**
	2002	(0.39)	1.27	0.36	(0.08)

(A) These amounts have been restated due to Enogex s exploration and production assets, NuStar and Belvan being reported as discontinued operations during 2003 and 2002.

(B) In the third quarter of 2002, the Company restated revenues to report on a net basis, all realized gains and losses from energy trading contracts (accounted for under EITF 98-10) that resulted in physical delivery as required by EITF 02-3. In the fourth quarter of 2002, the EITF reversed their previous position regarding this issue, and returned to the previous method of reporting these revenues on a gross basis.

(C) In the fourth quarter of 2002, the Company recognized a pre-tax impairment loss of approximately $48.3 million and $1.8 million in the Natural Gas Pipeline segment and Other Operations, respectively. The impairment loss in the Natural Gas Pipeline segment related to natural gas processing and compression assets. The impairment loss in Other Operations related to the Company s aircraft.

(D) In the fourth quarter of 2003, the Company recognized a pre-tax impairment loss of approximately $9.2 million and $1.0 million in the Natural Gas Pipeline segment and Other Operations, respectively. The impairment loss in the Natural Gas Pipeline segment related to natural gas compression assets. The impairment loss in Other Operations related to the Company s aircraft.

Dividends

COMMON STOCK

Common quarterly dividends paid (as declared) in 2003, 2002, and 2001 were $0.33 ¼.
Present rate $0.33 ¼
Payable 30th of January, April, July, and October

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Security Ratings*

	Moody s	Standard & Poor s	Fitch s
OG&E Senior Notes	A2	BBB+	AA-
Enogex Notes	Baa3	BBB+	BBB
OGE Energy Corp. Commercial Paper	P-2	A-2	F1

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

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

Market Prices

	2003		2002	
NEW YORK STOCK EXCHANGE	**High**	**Low**	High	Low
Common				
First Quarter	**$ 19.37**	**$ 15.99**	$ 24.12	$ 21.28
Second Quarter	**22.25**	**17.36**	24.24	21.82
Third Quarter	**22.75**	**19.50**	23.29	16.13
Fourth Quarter	**24.34**	**21.96**	18.34	13.70

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OG&E

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Oklahoma City, Oklahoma

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OGE ENERGY CORP.
Annual Meeting of Shareowners
May 20, 2004

OG&E

The undersigned hereby appoints Steven E. Moore, Herbert H. Champlin, and Martha W. Griffin, 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 22, 2004, at the Company's Annual Meeting of Shareowners to be held on May 20, 2004, and at all adjournments thereof, on all matters coming before said meeting.

THIS PROXY, WHICH IS SOLICITED BY THE BOARD OF DIRECTORS, WILL BE VOTED AS DIRECTED. IF NO DIRECTION IS MADE, THE PROXY WILL BE VOTED FOR THE ELECTION AS DIRECTORS OF THE NOMINEES NAMED ON THE REVERSE SIDE OF THIS PROXY CARD.

PLEASE VOTE BY INTERNET, TELEPHONE, OR MARK, DATE, SIGN AND RETURN THIS PROXY CARD PROMPTLY USING THE ENCLOSED ENVELOPE. Unless you attend and vote in person, you MUST vote by Internet, telephone, or sign and return your proxy in order to have your shares voted at the meeting.

(Continued on reverse side)

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

	FOR all NOMINEES (list exceptions below)	WITHHOLD AUTHORITY to vote for all nominees
1. Election of Directors NOMINEES: 01 Luke R. Corbett 02 Robert Kelley 03 J.D. Williams	______	______

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

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

Consenting to receive all future annual meeting materials and shareholder communications electronically is simple and fast! Enroll today at www.melloninvestor.com/ISD for secure online access to your proxy materials, statements, tax documents and other important shareholder correspondence.

Discontinue mailing of duplicate Annual Report ____

I will attend the Annual Meeting. ____

X ______________________ / / 2004

Signature of Shareowner Date

X ______________________ / / 2004

Signature of Shareowner Date

OG&E

321 North Harvey Avenue
Oklahoma City, Oklahoma 73102

Admission Ticket

RETAIN FOR ADMITTANCE

Annual Meeting of

OGE Energy Corp. Shareowners

Thursday, May 20, 2004 10:00 a.m.
National Cowboy and Western Heritage Museum
1700 Northeast 63rd Street
Oklahoma City, Oklahoma

LOCATION OF THE NATIONAL COWBOY AND WESTERN HERITAGE MUSEUM

East Bound or West Bound I-44

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

MAP

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.

Vote by Internet or Telephone or Mail

24 Hours a Day, 7 Days a Week

Internet and telephone voting is available through 11:59 PM Eastern Time the day prior to annual meeting day.

Your Internet or telephone vote authorizes the named proxies to vote your shares in the same manner as if you marked, signed and returned your proxy card.

Internet **http://www.eproxy.com/oge**		**Telephone** **1-800-435-6710**		**Mail**
Use the internet to vote your proxy. Have your proxy card in hand when you access the web site.	OR	Use any touch-tone telephone to vote your proxy. Have your proxy card in hand when you call.	OR	Mark, sign and date your proxy card and return it in the enclosed postage-paid envelope.

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

You can view the Annual Report and Proxy Statement on the internet at http:www.oge.com