UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

(Mark One)

[X] ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2003

OR

[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from ______ to ______ Commission File Number 1-12579

OGE ENERGY CORP.
(Exact name of registrant as specified in its charter)

Oklahoma	**73-1481638**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

321 North Harvey
P.O. Box 321
Oklahoma City, Oklahoma 73101-0321
(Address of principal executive offices)
(Zip Code)
Registrant's telephone number, including area code: **(405) 553-3000**

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common Stock	New York Stock Exchange and Pacific Stock Exchange
Rights to Purchase Series A Preferred Stock	New York Stock Exchange and Pacific Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes X No__

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. [ ]

Indicate by check mark whether the registrant is an accelerated filer (as defined in Rule 12b-2 of the Act). Yes X No__

As of June 30, 2003, the last business day of the registrant's most recently completed second fiscal quarter, the aggregate market value of shares of common stock held by non-affiliates was $1,704,295,645 based on the number of shares held by non-affiliates (79,751,785) and the reported closing market price of the common stock on the New York Stock Exchange on such date of $21.37.

As of January 31, 2004, 87,469,884 shares of common stock, par value $0.01 per share, were outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

The Proxy Statement for the Company's 2004 annual meeting of stockholders is incorporated by reference into Part III of this Form 10-K.

OGE ENERGY CORP.

FORM 10-K

FOR THE YEAR ENDED DECEMBER 31, 2003

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PART I

Item 1. Business.

THE COMPANY

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.

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 “Regulation and Rates – State Restructuring Initiatives and National Energy Legislation.”

On October 11, 2002, OG&E, the OCC Staff, the Oklahoma Attorney General and other interested parties agreed to a settlement (the “Settlement Agreement”) of OG&E’s rate case. The terms of the settlement are described below in “Regulation and Rates – 2002 Settlement Agreement.”

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 was incorporated in August 1995 in the State of Oklahoma and its principal executive offices are located at 321 North Harvey, P.O. Box 321, Oklahoma City, Oklahoma 73101-0321; telephone (405) 553-3000.

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.

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. See “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations – Company Strategy” for a further discussion.

ELECTRIC OPERATIONS - - OG&E

General

The Electric Utility segment generates, transmits, distributes and sells electric energy in Oklahoma and western Arkansas. Its operations are conducted through OG&E. OG&E furnishes retail electric service in 270 communities and their contiguous rural and suburban

areas. During 2003, five other communities and three rural electric cooperatives in Oklahoma and western Arkansas purchased electricity from OG&E for resale. The service area, with an estimated population of 1.9 million, covers approximately 30,000 square miles in Oklahoma and western Arkansas; including Oklahoma City, the largest city in Oklahoma, and Fort Smith, Arkansas. Of the 270 communities served, 244 are located in Oklahoma and 26 in Arkansas. Approximately 89 percent of total electric operating revenues for the year ended December 31, 2003, were derived from sales in Oklahoma and the remainder from sales in Arkansas.

OG&E's system control area peak demand as reported by the system dispatcher during 2003 was approximately 5,977 MWs on August 21, 2003. OG&E's load responsibility peak demand was approximately 5,657 MWs on August 21, 2003, resulting in a capacity margin of approximately 14.0 percent. As reflected in the table below and in the operating statistics on page 4, there were approximately 25.1 million megawatt-hour ("MWH") sales in 2003 as compared to approximately 24.9 million in 2002 and 2001. MWH sales to OG&E's customers ("system sales") increased approximately 1.6 percent in 2003, due to increased usage related to customer growth in OG&E's service territory partially offset by milder weather during 2003. Sales to other utilities and power marketers ("off-system sales") decreased approximately 67.0 percent in 2003, due to the changing supply and demand needs on OG&E's generation system.

Variations in MWH sales for the three years are reflected in the following table:

	2003	**Increase/ (Decrease)**	2002	Increase/ (Decrease)	2001	Increase/ (Decrease)
System Sales (A)	**25.0**	**1.6%**	24.6	0.4%	24.5	(2.0)%
Off-System Sales (A)	**0.1**	**(67.0)%**	0.3	(25.0)%	0.4	33.3%
Total Sales	**25.1**	**0.8%**	24.9	---	24.9	(1.6)%

(A) Sales are in million of MWHs.

OG&E is subject to competition in various degrees from government-owned electric systems, municipally-owned electric systems, rural electric cooperatives and, in certain respects, from other private utilities, power marketers and cogenerators. Oklahoma law forbids the granting of an exclusive franchise to a utility for providing electricity.

Besides competition from other suppliers or marketers of electricity, OG&E competes with suppliers of other forms of energy. The degree of competition between suppliers may vary depending on relative costs and supplies of other forms of energy. See "Regulation and Rates – State Restructuring Initiatives and National Energy Legislation" for a discussion of the potential impact on competition from federal and state legislation.

OKLAHOMA GAS AND ELECTRIC COMPANY
CERTAIN OPERATING STATISTICS

Year ended December 31 *(In millions)*	**2003**	2002	2001
ELECTRIC ENERGY			
(Millions of MWH)			
Generation (exclusive of station use)	**22.5**	23.4	23.0
Purchased	**4.5**	3.5	3.7
Total generated and purchased	**27.0**	26.9	26.7
Company use, free service and losses	**(1.9)**	(2.0)	(1.8)
Electric energy sold	**25.1**	24.9	24.9
ELECTRIC ENERGY SOLD			
(Millions of MWH)			
Residential	**8.2**	8.0	8.0
Commercial and industrial	**12.6**	12.4	12.4
Public street and highway lighting	**0.1**	0.1	0.1
Other sales to public authorities	**2.6**	2.6	2.5
System sales for resale	**1.5**	1.5	1.5
Total system sales	**25.0**	24.6	24.5
Off-system sales	**0.1**	0.3	0.4
Total sales	**25.1**	24.9	24.9
ELECTRIC OPERATING REVENUES			
(In millions)			
Residential	**$ 601.4**	$ 557.6	$ 578.9
Commercial and industrial	**665.9**	605.5	638.0
Public street and highway lighting	**11.1**	10.4	10.9
Other sales to public authorities	**135.0**	125.1	127.9
System sales for resale	**57.7**	48.2	52.5
Provision for FERC rate refund	---	---	(1.0)
Total system sales	**1,471.1**	1,346.8	1,407.2
Off-system sales	**4.1**	6.3	13.0
Total Electric Revenues	**1,475.2**	1,353.1	1,420.2
Miscellaneous revenues	**41.9**	34.9	36.6
Total Electric Operating Revenues	**$ 1,517.1**	$ 1,388.0	$ 1,456.8

ACTUAL NUMBER OF ELECTRIC CUSTOMERS			
(At end of period)			
Residential	**622,527**	616,712	609,408
Commercial and industrial	**89,235**	88,466	87,511
Public street and highway lighting	**249**	249	250
Other sales to public authorities	**13,409**	13,031	12,566
Sales for resale	**50**	55	62
Total	**725,470**	718,513	709,797
AVERAGE RESIDENTIAL CUSTOMER SALES			
Average annual revenue	**$ 970.04**	$ 907.95	$ 952.32
Average annual use (kilowatt-hour ("KWH"))	**13,202**	13,095	13,131
Average price per KWH (cents)	**$ 7.35**	$ 6.93	$ 7.25

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 electric generation ("New Generation") of not less than 400 megawatts ("MW") 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 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 520 MW NRG McClain Station (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 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 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.

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.

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 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.

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

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. The OCC is currently reviewing the appropriateness of gas transportation charges under the agreement between OG&E and Enogex. See "Gas Transportation and Storage Agreement" for a further discussion. OG&E believes the amount currently paid to Enogex for transportation and storage services is fair, just and reasonable. All of the storage costs and a portion of the gas transportation costs are included in either base rates or are recoverable through OG&E's automatic fuel adjustment clause. See "Regulation and Rates – Other Regulatory Actions" for a further discussion.

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 the 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 independent power producers ("IPP"). 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 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 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.

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 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.

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.

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.

Rate Activities and Proposals

In 2002, OG&E concluded its Oklahoma rate review proceeding before the OCC. This rate review was initiated in September 2001 by the OCC Staff and was concluded by order of the OCC on November 20, 2002. Under the rate review, OG&E, the OCC Staff, the Oklahoma Attorney General and other interested parties agreed to a Settlement Agreement which stipulated that OG&E would file tariffs, designed to reflect an annual reduction of $25.0 million in OG&E's

Oklahoma jurisdictional operating revenue. The $25.0 million annual reduction began on January 6, 2003. The Settlement Agreement addressed the importance of OG&E acquiring New Generation. See "Regulation and Rates — Pending Acquisition of Power Plant" for the

issues facing OG&E in its acquisition of the McClain Plant in accordance with the Settlement Agreement.

Other elements of importance addressed in the Settlement Agreement included a modification of the sharing ratio of off-system sales and the recognition of the reduction of cogeneration costs in OG&E's retail rates in the years 2003 and beyond.

OG&E also received OCC approval in the Settlement Agreement for several new customer programs and rate options, as well as modifications to existing rate structures. The Guaranteed Flat Bill ("GFB") option for residential and small general service accounts allows qualifying customers the opportunity to purchase their electricity needs at a set price for an entire year. Budget-minded customers that desire a fixed monthly bill benefit from the GFB option. A second tariff rate option approved in the Settlement Agreement is an offering to provide a "renewable energy" resource to OG&E's Oklahoma retail customers. This renewable energy resource is a wind power purchase program and is available as a voluntary option to all of OG&E's Oklahoma retail customers. Oklahoma's availability of wind resources makes the renewable wind power option a possible choice in meeting the renewable energy needs of our conservation-minded customers. A third new rate offering available to commercial and industrial customers is levelized demand billing. This program is beneficial for medium to large size customers with seasonally consistent demand levels who wish to reduce the variability of their monthly electric bills. The levelized demand offering is not for every customer, but many customers will benefit from this program. The last new program being offered to OG&E's commercial and industrial customers and approved by the OCC is a new voluntary load curtailment program. This program provides customers with the opportunity to curtail on a voluntary basis when OG&E's system conditions merit curtailment action. Customers that curtail their usage will receive payment for their curtailment response. This voluntary curtailment program seeks customers that can curtail on most curtailment event days, but may not be able to curtail every time that a curtailment event is required.

The previously discussed new rate options coupled with OG&E's existing rate choices provide many tariff options for OG&E's Oklahoma retail customers. OG&E's rate choice flexibility, reduction in cogeneration rates, acquisition of additional generation resources and overall low costs of production and deliverability are expected to provide valuable benefits for our customers for many years to come. OG&E began implementation of the new rate options during the first billing cycle in January 2003. Since many of these options are voluntary, customers may choose these options anytime after the January 2003 start date. The revenue impacts associated with these options are indeterminate in future years since customers may choose to remain on existing rate options instead of volunteering for the new rate option choices. There was no overall material impact in 2003 associated with these new rate options, but minimal revenue variations may occur in the future based upon changes in customers' usage characteristics if they choose these new programs.

Fuel Supply

During 2003, approximately 77 percent of the OG&E-generated energy was produced by coal units and 23 percent by natural gas units. Of the 5,660 total MW capability reflected in the

table under Item 2. Properties, approximately 3,125 MWs or 55 percent are from natural gas generation and approximately 2,535 MWs or 45 percent are from coal generation. 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 using lower priced coal. A slight decline in the percentage of coal generation in future years is expected to result from increased usage of natural gas generation required to meet growing energy needs. Over the last five years, the average cost of fuel used, by type, per million British thermal unit ("MMBtu") was as follows:

	2003	2002	2001	2000	1999
Coal	**$ 0.93**	$ 0.93	$ 0.81	$ 0.87	$ 0.85
Natural Gas	**$ 6.46**	$ 3.78	$ 4.91	$ 4.93	$ 3.14
Weighted Average	**$ 2.27**	$ 1.77	$ 1.97	$ 1.96	$ 1.54

A portion of the fuel cost is included in base rates and differs for each jurisdiction. The portion of these costs that is not included in base rates is recovered through automatic fuel adjustment clauses. See "Regulation and Rates – Automatic Fuel Adjustment Clauses."

Coal

All of OG&E's coal units, with an aggregate capability of approximately 2,535 MWs, are designed to burn low sulfur western coal. OG&E purchases coal primarily under long-term contracts expiring in 2010 and 2011. During 2003, OG&E purchased approximately 9.7 million tons of coal from the following Wyoming suppliers: Kennecott Energy Company, Arch Coal Inc., Peabody Coal Sales Company and Triton Coal Company. The combination of all coal has a weighted average sulfur content of less than 0.24 percent and can be burned in these units under existing federal, state and local environmental standards (maximum of 1.2 lbs. of sulfur dioxide per MMBtu) without the addition of sulfur dioxide removal systems. Based upon the average sulfur content, OG&E's units have an approximate emission rate of 0.504 lbs. of sulfur dioxide per MMBtu well within the limitations of the provisions of Phase II of The Clean Air Act.

OG&E has continued its efforts to maximize the utilization of its coal units at both the Sooner and Muskogee generating plants. See "Environmental Matters" for a discussion of an environmental proposal that, if implemented as proposed, could inhibit OG&E's ability to use coal as its primary boiler fuel.

Natural Gas

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.

In 1993, OG&E began utilizing a natural gas storage facility that allows OG&E to optimize the use of its generation assets.

NATURAL GAS PIPELINE OPERATIONS - ENOGEX

The operations of the Natural Gas Pipeline segment are conducted through 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. 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. Enogex and its subsidiaries operate approximately 8,000 miles of intrastate gas gathering and transportation pipelines. Additionally, through a 75 percent interest in NOARK, Enogex also owns a controlling interest in and operates Ozark, an approximately 931 mile 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 transportation, storage and gathering assets of Enogex provide OG&E strategic access to natural gas supplies, and flexible and reliable delivery terms that are required to fuel OG&E's natural gas-fired generation facilities. Natural gas generation peaking units require the ability to quickly change their status, to meet both the peak and off-peak demands of the retail load particularly when coal units have an unscheduled outage. The gathering assets access major wellhead supply sources primarily located across Oklahoma and Arkansas, and the integrated transportation and storage assets provide the ability to regulate the receipt and delivery of natural gas to match the instantaneous needs of these generation units.

Natural gas-fired generation units contribute their highest value when they have the capability to provide "load following" service to the customer. While the physical characteristics of natural gas units are known to provide quick start-up and on-line functionality, and while their ability to efficiently provide varying levels of electric generation relative to other forms of generation is further acknowledged, their ultimate effectiveness is contingent upon having access to an integrated pipeline and storage system that can respond in a short term fashion to meet its corresponding fluctuating operational fuel requirements. The combination of these assets is critical to a generator's ability to provide reliable generation service at reasonable prices to the consumer.

Not only is Enogex providing service to OG&E, but Enogex's same assets provide firm and interruptible services to a significant portion of the other natural gas-fired generation loads in the State of Oklahoma and numerous other generation loads in the adjoining States of Texas and Arkansas. Enogex understands the needs of generators, and more importantly has the appropriately-sized pipelines, compression and integrated storage assets necessary to meet their requirements.

Through Enogex's gathering and processing assets, Enogex aggregates gas supplies for both its own markets, and also for those markets accessible via its numerous intrastate and interstate pipeline connections. It aggressively pursues new supplies from wells drilled by

producers primarily in the Anadarko and Arkoma basins. Oklahoma ranks third in the nation in natural gas production. The system capacity, due to its large diameter gathering pipelines and its natural gas processing plants, is capable of adapting to the varying pressure and quality requirements of mid-continent production. Enogex is able to provide low-pressure service to extend the production life of older wells as well as meeting the high-pressure requirements of new exploration. Enogex is also able to remove natural gas liquids from the wellhead gas streams, by processing the gas, which would otherwise prevent such gas from meeting the British thermal unit ("Btu") and quality specifications of the downstream marketplace and therefore could not be produced.

The activities described above, while central to Enogex's operations, are not its only businesses. The transportation capabilities and "on and off-system" markets of the pipeline assets provide other business opportunities. This equally important and valuable feature of Enogex and its assets is the ability of Enogex to use its pipeline system and storage assets as a "market hub". At December 31, 2003, excluding the pipeline connection between its intrastate pipeline and the Ozark pipeline, Enogex was connected to 15 other major pipelines at approximately 60 pipeline interconnect points providing access to markets in the western United States, the mid-west, northeast, and gulf coast in addition to Oklahoma and adjoining states. Therefore, regardless of the constantly varying relationship between supply and demand, both in volume and location, Enogex's assets sit in a key geographic region of the United States, with sufficient capacity to provide cross-haul transportation and storage services to a variety of utility and industrial customers that need to access mid-continent supply for their own needs, or to suppliers from other regions seeking to provide gas to on-system markets which Enogex serves.

Enogex's marketing and trading business is an important element in realizing the full value of its transportation and storage assets and in providing products and services that support the market hub concept. The marketing and trading business offers the Company real-time and longer-term price discovery and valuation of energy commodities (natural gas and associated natural gas liquids) associated with the Company's assets. The marketing and trading business also is instrumental in providing increased liquidity for these energy commodities, by focusing on developing supplies and markets that can access the Enogex systems either directly or via interconnections with intrastate and interstate pipelines. The marketing and trading business also provides the Company the capability of providing risk management services to its customers.

The Company intends to continue to build upon the foundation of services and products that these assets can provide. In addition, the Company expects to generate additional margins by improving its ability to aggregate gas, maximize the operational capabilities of its assets and utilize commercial information available from the marketplace.

Recent Actions

Beginning in 2002, Enogex evaluated, redesigned and reorganized its internal work processes and senior management structure in order to achieve cost reductions, revenue enhancements and strategic leadership within its businesses.

After a review of Enogex's assets on the basis of their strategic value and other factors, the Company sold all of its exploration and production assets and its interest in Belvan Corp.,

Belvan Limited Partnership and Todd Ranch Limited Partnership ("Belvan") in 2002 and its interest in the NuStar Joint Venture ("NuStar") in February 2003. These dispositions have been reported as discontinued operations for the years ended December 31, 2003, 2002 and 2001 in the Consolidated Financial Statements.

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 any 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.

During the fourth quarter of 2002, the Company recognized a pre-tax impairment loss of approximately $48.3 million 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, 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.

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 recorded 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.

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 on revenues 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 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 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.

Transportation and Storage

General. One of Enogex’s primary lines of business is the transportation of natural gas, with current throughput of approximately 1.4 billion cubic feet per day (“Bcfd”). Enogex delivers natural gas to most interstate and intrastate pipelines and end-users connected to its systems from the Arkoma basin of eastern Oklahoma and Arkansas, the Anadarko basin of western Oklahoma and the Panhandle of west Texas. At December 31, 2003, excluding the pipeline connection between its intrastate pipeline and the Ozark pipeline, Enogex was connected to 15 other major pipelines at approximately 60 pipelines interconnect points. These interconnections include Panhandle Eastern Pipe Line, Southern Star Central Gas Pipeline (formerly Williams Central), Natural Gas Pipeline Company of America, Oneok Gas Transmission, Northern Natural Gas Company, ANR Pipeline, Western Farmers Electric Cooperative, CenterPoint Energy Gas Transmission Co., Black Marlin Pipeline, El Paso Natural Gas Pipeline, Kansas Pipeline and Oneok WesTex Transmission L.P., as well as connections via Enogex’s Ozark system to Texas Eastern and Mississippi River Transmission. Further, Enogex

is connected to various end-users including numerous electric generation facilities in Oklahoma that are fueled by natural gas. At December 31, 2003, the net property, plant and equipment balance for Enogex’s transportation and storage business was approximately $733.0 million.

Enogex owns two storage facilities in Oklahoma, the Wetumka Storage Facility and the Stuart Storage Facility. These storage facilities are currently being operated at a working gas level of approximately 24.5 billion cubic feet (“Bcf”) with an approximate withdrawal capability of 650 million cubic feet per day (“MMcfd”) and similar injection capability. Enogex offers both firm and interruptible storage services to third parties, under Section 311 of the Natural Gas Policy Act (“NGPA”), under terms and conditions specified in its Statement of Conditions for Gas Storage and at market-based rates to be negotiated with each customer. During 2002, Enogex expensed approximately $4.0 million for natural gas inventory losses associated with the Wetumka Storage Facility. While some gas losses are normally associated with the operation of a natural gas storage field, the 2002 amount exceeded acceptable levels. The Stuart Storage Facility is used to support Enogex’s intrastate transportation and storage services for OG&E. During 2003, Enogex made improvements to these two storage fields. The repair project at the Wetumka Storage Facility was designed to mitigate any 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. See "Item 3. Legal Proceedings" for a discussion of the pending litigation associated with the Stuart Storage Facility.

Enogex offers interruptible Section 311 transportation services as well as both firm and interruptible services to intrastate customers with a majority of transportation revenues derived from firm contracts. Enogex offers interruptible service to customers when capacity is available.

Effective January 1, 2002, the Enogex and Transok L.L.C. and its subsidiary entities ("Transok") merged thereby simplifying for both Enogex and its customers the administration and operation of maintaining two separate pipelines. Enogex provides firm intrastate transportation services to OG&E as well as Public Service Company of Oklahoma ("PSO"), the second largest electric utility in Oklahoma, serving the Tulsa market. In July 1999, Enogex acquired Transok. Transok maintained a sole-supplier relationship with PSO until 1998, when Oklahoma Natural Gas began supplying gas to three of the PSO generating stations pursuant to a competitive bid process put in place by the OCC. Notwithstanding the loss of the sole-supplier status, Enogex remains the primary supplier to PSO. Enogex continues to provide gas transmission delivery services to all of PSO's natural gas-fired electric generation units in Oklahoma under a firm intrastate transportation contract. The current PSO contract, which expires January 1, 2005, and the OG&E contract, which expires April 30, 2009, provide for a monthly demand charge plus variable transportation charges (including fuel). As part of the contract with OG&E, Enogex provides additional natural gas storage services for OG&E. Enogex has been providing these natural gas storage services since August 2002 when Enogex exercised its option to purchase the Stuart Storage Facility to collect on its judgment against Central Oklahoma Oil and Gas Corp. ("COOG"). In addition, Enogex provides transportation

services via the leased Palo Duro pipeline system to Houston Pipe Line Company ("HPC"), an affiliate of PSO, for gas delivery service to certain HPC generating stations in the Texas panhandle. Enogex's lease of the Palo Duro pipeline terminated effective June 30, 2003. On June 27, 2003, Enogex sent notice to the FERC indicating that its lease of the Palo Duro pipeline had terminated, and that Enogex would no longer be offering Section 311 service to Palo Duro shippers. Enogex has extended its lease of a small segment of gathering pipeline off of the Palo Duro system, referred to as the Northeast Lateral. The term of the lease extension of the Northeast Lateral expires February 28, 2005, and will remain in effect month to month thereafter, subject to termination by either Enogex or the lessor upon 60 days notice. Though the Palo Duro system, including the Northeast Lateral, were sold from the lessor to a third party in 2004, Enogex has not received termination notice and continues to operate under the monthly lease terms. During 2003, 2002 and 2001, Enogex's revenues from the contracts with OG&E, PSO and HPC were approximately $63.0 million, $57.1 million and $55.1 million, respectively.

Relationship with OG&E. From its inception, Enogex has been the exclusive transporter of natural gas to OG&E's natural gas-fired generation facilities. Although Enogex is not directly regulated by the OCC, OG&E's rates are subject to OCC jurisdiction. The OCC issued an order on November 20, 2002 which contained a provision, among other things, that OG&E would consider competitive bidding as an option in obtaining gas transportation service for its natural gas-fired generation facilities when the contract with Enogex expired. The term of the then current contract was to expire in April 2004. Subsequently, this contract was amended by an agreement dated May 1, 2003 with no-notice load following requirements and a termination date of April 30, 2009. As part of the contract with OG&E, Enogex provides additional natural gas storage services for OG&E. Enogex has been providing these natural gas storage services since August 2002 when Enogex exercised its option to purchase the Stuart Storage Facility to collect on its judgment against COOG. The amount collected from OG&E by Enogex under the current contract for transportation services was approximately $33.5 million, $33.6 million and $36.3 million, respectively, during 2003, 2002 and 2001. The amount collected from OG&E by Enogex under the current contract for storage services was approximately $11.2 million and $3.3 million, respectively, during 2003 and 2002. Enogex did not provide storage services to OG&E during 2001.

Competition. Enogex's transportation and storage assets compete with interstate and other intrastate pipeline and storage facilities in providing transportation and storage services for natural gas. The principal elements of competition are rates, terms of services, flexibility and reliability of service.

Natural gas competes with other forms of energy available to Enogex's customers and end-users, including electricity, coal and fuel oils. The primary competitive factor is price. Changes in the availability or price of natural gas or other forms of energy as well as weather and other factors affect the demand for natural gas on the Enogex system.

Regulation. The rates charged by Enogex for transporting natural gas on behalf of an interstate natural gas pipeline company or a local distribution company served by an interstate natural gas pipeline company are subject to the jurisdiction of the FERC under Section 311 of the NGPA. Rates to provide such service must be "fair and equitable" under the NGPA and are

subject to review and approval by the FERC at least once every three years. This rate review may involve an administrative-type trial and an administrative appellate review. By offering interruptible Section 311 transportation, the regulatory burden on Enogex is not appreciably increased, but does give Enogex the opportunity to utilize any unused capacity on an interruptible basis in interstate commerce and thus increase its transportation revenues. See "FERC Section 311 Case" for a discussion of Enogex's most recent Section 311 case.

The Company, through Enogex, owns a 75 percent interest in Ozark. Ozark transports natural gas in interstate commerce. As a result, Ozark qualifies as a "natural gas company" under the Natural Gas Act of 1938 (the "Natural Gas Act"), and is subject to the regulatory jurisdiction of the FERC. Under the Natural Gas Act, the FERC has jurisdiction to review and authorize the proposed construction of facilities for the transportation of natural gas in interstate commerce, the rendition of service through interstate facilities, the rates charged for such service and the abandonment of such facilities or services.

The Natural Gas Act requires that the rates charged, and the terms and conditions of service observed, by interstate pipelines be "just and reasonable", and not unduly discriminatory or preferential. All rates and terms and conditions of service proposed by an interstate pipeline must be filed with the FERC, and the FERC has jurisdiction under the Natural Gas Act to determine whether proposed rates or terms and conditions meet the statutory standards. The Natural Gas Act confers upon the FERC authority to determine a jurisdictional pipeline's rates, charges and terms and conditions of service, to establish depreciation rates and to prescribe uniform systems of accounts.

The rates charged by Enogex for transporting natural gas for OG&E and other shippers within Oklahoma are not subject to FERC regulation because they are intrastate transactions. With respect to state regulation, the rates charged by Enogex for any intrastate transportation service have not been subject to direct state regulation by the OCC, which is the state agency responsible for setting rates of public utilities within Oklahoma. Even though the intrastate pipeline business of Enogex is not directly regulated by the OCC, the OCC, the APSC and the FERC (all of which approve various electric rates of OG&E) have the authority to examine the appropriateness of any transportation charges or other fees paid by OG&E to Enogex which OG&E seeks to recover from its ratepayers in its cost-of-service for electric service. See "Relationship with OG&E" above for a discussion of competitive bidding for OG&E's service.

Enogex's pipeline operations are subject to various Oklahoma safety and environmental and non-discriminatory transportation requirements.

Gathering and Processing

General. Natural gas gathering operations are conducted through Enogex Gas Gathering L.L.C., and natural gas processing operations are conducted through Enogex Products Corporation ("Products"). The streams of processable natural gas gathered from wells and other sources are gathered through Enogex's gas gathering systems and delivered to processing plants for the extraction of natural gas liquids. During 2003, the gathering systems connected approximately 232 producing wells located primarily in the Anadarko and Arkoma basins of

Oklahoma and Arkansas represented by 103 contracts with 72 producers. The Company provides connection, measurement, treating, dehydration and compression services for various types of producing wells owned by various sized producers who are active in the region. Where the quality of natural gas received dictates that removal of natural gas liquids may be in order, such gas is aggregated via the gathering system to the inlet of one or more of the Company's fleet of processing plants operated by Products. The resulting processed stream of natural gas is then delivered via the Enogex pipeline system to one or more delivery points into the web of transmission pipelines in the region. Products is one of the largest gas processors in the state of Oklahoma, operating six gas processing plants with a total inlet capacity of 678 MMcfd. During 2002, Products had ownership interests in two other gas processing plants related to NuStar, which were sold in February 2003. In 2003, approximately 259 million gallons of natural gas liquids were produced. Products has been active since 1968 in the processing of natural gas and extraction and marketing of natural gas liquids. The liquids extracted include condensate, marketable ethane, propane, butanes and natural gasoline mix. The residue gas remaining after the liquid products have been extracted consists primarily of ethane and methane. At December 31, 2003, the net property, plant and equipment balance for Enogex's gathering and processing business was approximately $308.4 million.

Approximately 24 percent of the commercial grade propane processed at Products' plants is sold on the local market. The balance of propane and the other natural gas liquids produced by Products are delivered into pipeline facilities of Koch Hydrocarbon and transported to Conway, Kansas and Mont Belvieu, Texas, where they are sold under contract or on the spot market. Ethane, which may be optionally produced at all of Products' plants except one, is sold in the spot market.

During 2002, Enogex initiated steps to decrease the volatility of its earnings stream by reducing its exposure to keep whole processing arrangements. Keep whole processing arrangements generally require a processor of natural gas to keep its shippers whole on a Btu basis by replacing the Btu value of the liquids extracted from the well stream with natural gas at market prices. Therefore, if natural gas prices increase and liquids prices do not increase by a corresponding amount, processing margins are negatively affected. In order to minimize the negative impact on processing margins, ethane and propane are rejected based upon then current market conditions. Exposure to keep whole processing arrangements was reduced through contract renegotiations and changes in the standards of service provided by Enogex under the FERC Section 311 filing discussed previously that provides for a default processing fee in the event the fractionation spreads (the difference between the price of natural gas liquids extracted and natural gas) are negative. As a result, in months in which commodity spreads were negative thus activating the default processing fee allowed in the SOC, the exposure to keep whole processing arrangements has been reduced. Further, when market conditions dictated, Products took active steps to reduce the amount of natural gas at the plant inlet to approximately 11 percent keep whole without the default processing fee. In addition, the Company actively monitors current and future commodity prices for opportunities to hedge its processing margin. Enogex has executed physical and financial hedges by selling liquids forward as well as hedging the fractionation spread of various liquids' components.

As discussed above, the Company sold all of its interest in Belvan in 2002 and its interest in NuStar in February 2003.

Competition. Enogex competes with gatherers of all types and sizes, including those affiliated with various producers, other major pipeline companies, as well as various independent gatherers. In processing and marketing natural gas liquids, Products competes against virtually all other gas processors producing and selling natural gas liquids. Competition for natural gas supply is based on efficiency and reliability of operations, reputation, availability of gathering and transportation to markets and pricing arrangements offered by the gatherer/processor. Enogex believes it will be able to continue to compete against such companies.

With respect to the profitability of the natural gas liquids industry generally, as the price of natural gas liquids falls without a corresponding decrease in the price of natural gas, it may become uneconomical to extract certain natural gas liquids. This factor had a significant adverse impact on the results of Enogex during 2001 but as discussed above, the potential adverse impact has been materially mitigated, but not entirely eliminated. In addition to the commodity pricing impact that affects the entire industry, the profitability of Products is also largely affected by the volume of natural gas processed at its plants which is highly dependent upon the volume and Btu content of natural gas gathered. Generally, if the volume of natural gas gathered increases, then the volume of liquids extracted by Products should also increase.

Marketing and Trading

Enogex's commodity sales and services related to natural gas are conducted primarily through its subsidiary, OGE Energy Resources, Inc. ("OERI").

OERI is engaged in the business of natural gas marketing. OERI's agreements with Enogex provide for OERI to provide marketing services for all natural gas volumes purchased by Enogex at the wellhead from producers or otherwise. As a service to the producers on the Enogex system, Enogex may agree to purchase the gas at the wellhead in conjunction with gathering their gas for transportation to other markets.

OERI also purchases and sells natural gas pursuant to contracts with Enogex and Products relating to Enogex's gathering, processing and storage assets. Prior to the sale of Enogex's exploration assets in 2002, OERI marketed the natural gas produced by Enogex Exploration Corporation ("Exploration"). At December 31, 2003, the net property, plant and equipment balance for Enogex's marketing and trading business was approximately $1.8 million.

OERI focuses on serving customers along the natural gas value chain, from producers to end-users, by purchasing natural gas from suppliers both on and off the Enogex and Ozark pipeline systems and reselling to pipelines, local distribution companies and end-users, including the electric generation sector.

The geographic scope of marketing efforts has been focused largely in the mid-continent area of the United States. These markets are natural extensions of OERI's business on the Enogex system. OERI contracts for pipeline capacity with Enogex and other pipelines to access multiple interconnections with the interstate pipeline system network that moves natural gas from the production basins in the south central United States to the major consumption areas in Chicago, New York and other north central and mid-Atlantic regions of the United States.

OERI participates in both intermediate-term markets (less than three years) and short-term "spot" markets for natural gas. Although OERI continues to increase its focus on intermediate-term sales, short-term sales of natural gas are expected to continue to play a critical role in the overall strategy because they provide an important source of market intelligence as well as an important portfolio balancing function. In 2003, OERI bought and sold approximately 1.0 Bcfd of natural gas.

OERI's risk management skills afford its customers the opportunity to tailor the risk profile and composition of their natural gas portfolio. The Company follows a policy of hedging price risk on gas purchases or sales contracts entered into by the marketing group by buying and selling natural gas futures contracts on the New York Mercantile Exchange futures exchange and other derivatives in the over-the-counter market, subject to daily and monthly trading stop loss limits of $2.5 million in accordance with corporate policies.

Competition. OERI competes in marketing and trading natural gas with major integrated oil companies, marketing affiliates of major interstate and intrastate pipelines, national and local natural gas brokers, marketers and distributors for natural gas supplies. Competition for natural gas supplies is based primarily on reputation, credit support, the availability of gathering and transportation to high-demand markets and the ability to obtain a satisfactory price for the producer's natural gas. Competition for sales to customers is based primarily upon reliability, services offered and the price of delivered natural gas.

For the year ended December 31, 2003, approximately 74 percent of OERI's service volumes were with electric utilities, local gas distribution companies, pipelines and producers. The remaining 26 percent of service volumes were to marketers, municipals, cooperatives and industrials. At December 31, 2003, approximately 76 percent of the exposure was to companies having investment grade ratings with Standard & Poor's Ratings Services ("Standard & Poor's") and approximately three percent having less than investment grade ratings. The remaining 21 percent of OERI's exposure is with privately held companies, municipals or cooperatives that were not rated by Standard & Poor's. OERI applies internal credit analyses and policies to these non-rated companies.

Exploration and Production

The Company sold all of its exploration and production assets in 2002. These dispositions have been reported as discontinued operations for the years ended December 31, 2003, 2002 and 2001 in the Consolidated Financial Statements. The exploration and production activities were conducted through Exploration, which was formed in 1988 primarily to engage in the development and production of oil and natural gas. Exploration focused its early drilling activity in the Antrim Devonian shale trend in the state of Michigan and in recent years had concentrated on drilling opportunities in Oklahoma. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Results of Operations – Enogex – Discontinued Operations" for a further discussion.

FINANCE AND CONSTRUCTION

Future Capital Requirements

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. See "Item 7. Management's Discussion and Analysis of Financial Conditions and Results of Operations – Liquidity and Capital Requirements" for a detailed discussion of the Company's capital requirements.

Variances in the actual cost of fuel used in electric generation (which includes the operating lease obligations for OG&E's railcar leases) and certain purchased power costs, as compared to the fuel component included in the cost-of-service for ratemaking, are passed through to OG&E's customers through automatic fuel adjustment clauses. Accordingly, while the cost of fuel related to operating leases and the vast majority of unconditional fuel purchase obligations of OG&E 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.

Capital Expenditures

The Company's current 2004 to 2006 construction program includes the purchase of New Generation as discussed below. 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 increase in natural gas prices, OG&E will also assess the feasibility of constructing additional base load coal-fired units. See "Regulation and Rates – Pending Acquisition of Power Plant" 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. The purchase price for the interest in the McClain Plant is approximately $159.9 million, subject to adjustment for prepaid gas and property taxes. Closing is currently delayed in response to an order of the FERC. See "Regulation and Rates – 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.

Future Sources of Financing

General

Management expects that internally generated funds, funds received from the 2003 equity offering, proceeds from the sales of common stock pursuant to the Company's Automatic Dividend Reinvestment and Stock Purchase Plan ("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. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Liquidity and Capital Requirements – Future Sources of Financing" for a table showing 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.

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 "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Liquidity and Capital Requirements – Future Capital Requirements" for potential financing needs upon a downgrade by Moody's Investors Service ("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.

Security Ratings

In January and February 2003, Standard & Poor's and Moody's lowered many of the credit ratings of OGE Energy Corp.'s, OG&E's and Enogex's debt. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Liquidity and Capital Requirements – Future Capital Requirements" for a more detailed discussion of such credit rating agency actions.

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 and divestitures of assets that may complement its existing portfolio. Permanent financing would be required for any such acquisitions.

ENVIRONMENTAL MATTERS

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

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/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/MWH) 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 any potential releases of 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 ("ODEQ"), 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. See "Item 3. Legal Proceedings" for a further discussion of this matter.

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.

EMPLOYEES

The Company and its subsidiaries had 2,941 employees at December 31, 2003.

ACCESS TO SECURITIES AND EXCHANGE COMMISSION FILINGS

The Company's web site address is *www.oge.com*. The Company makes available, free of charge through its web site, its annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and all amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Exchange Act as soon as reasonably practicable after such material is electronically filed with or furnished to the Securities and Exchange Commission under the heading "Investors", "SEC Filings."

Item 2. Properties.

OG&E owns and operates an interconnected electric generation, transmission and distribution system, located in Oklahoma and western Arkansas, which includes eight generating stations with an aggregate capability of approximately 5,660 MWs. The following table sets forth information with respect to OG&E's electric generating facilities, all of which are located in Oklahoma:

Station & Unit		Year Installed	Unit Design Type	Fuel Capability	Unit Run Type	2003 Capacity Factor (A)	Unit Capability (MWs)	Station Capability (MWs)
Seminole	1	1971	Steam-Turbine	Gas	Base Load	23.3%	520.4	
	2	1973	Steam-Turbine	Gas	Base Load	21.2%	507.6	
	3	1975	Steam-Turbine	Gas/Oil	Base Load	19.6%	489.0	1,517.0
Muskogee	3	1956	Steam-Turbine	Gas	Base Load	7.2%	166.0	
	4	1977	Steam-Turbine	Coal	Base Load	73.1%	500.5	
	5	1978	Steam-Turbine	Coal	Base Load	87.3%	514.0	
	6	1984	Steam-Turbine	Coal	Base Load	70.9%	502.0	1,682.5
Sooner	1	1979	Steam-Turbine	Coal	Base Load	82.1%	505.2	
	2	1980	Steam-Turbine	Coal	Base Load	79.9%	513.8	1,019.0
Horseshoe	6	1958	Steam-Turbine	Gas/Oil	Base Load	16.9%	168.5	
Lake	7	1963	Combined Cycle	Gas/Oil	Base Load	17.3%	227.5	
	8	1969	Steam-Turbine	Gas	Base Load	8.0%	380.5	
	9	2000	Combustion-Turbine	Gas	Peaking	2.3%(B)	45.5	
	10	2000	Combustion-Turbine	Gas	Peaking	6.1%(B)	45.5	867.5
Mustang	1	1950	Steam-Turbine	Gas	Peaking	0.6%(B)	53.0	
	2	1951	Steam-Turbine	Gas	Peaking	0.7%(B)	53.0	
	3	1955	Steam-Turbine	Gas	Base Load	16.6%	115.5	
	4	1959	Steam-Turbine	Gas	Base Load	21.9%	250.0	
	5	1971	Combustion-Turbine	Gas/Jet Fuel	Peaking	0.7%(B)	31.0	502.5
Conoco	1	1991	Combustion-Turbine	Gas	Base Load	56.1%	31.5	
	2	1991	Combustion-Turbine	Gas	Base Load	57.8%	31.0	62.5
Enid	1	1965	Combustion-Turbine	Gas	Peaking	--- (C)	---	
	2	1965	Combustion-Turbine	Gas	Peaking	--- (C)	---	
	3	1965	Combustion-Turbine	Gas	Peaking	--- (C)	---	
	4	1965	Combustion-Turbine	Gas	Peaking	--- (C)	---	---
Woodward	1	1963	Combustion-Turbine	Gas	Peaking	--- (B)	9.4	9.4
Total Generating Capability (all stations)								5,660.4

(A) 2003 Capacity Factor = 2003 Net Actual Generation / (2003 Net Maximum Capacity (Nameplate Rating in MWs) x Period Hours (8,760 Hours)).
(B) Peaking units, which are used when additional capacity is required, are also necessary to meet the SPP reserve margins.
(C) These units are currently inactive.

At December 31, 2003, OG&E's transmission system included: (i) 32 substations with a total capacity of approximately 14.2 million kilo Volt-Amps ("kVA") and approximately 3,959 structure miles of lines in Oklahoma; and (ii) two substations with a total capacity of approximately 1.5 million kVA and approximately 252 structure miles of lines in Arkansas. OG&E's distribution system included: (i) 340 substations with a total capacity of approximately 9.3 million kVA, 22,494 structure miles of overhead lines, 1,859 miles of underground conduit and 7,565 miles of underground conductors in Oklahoma; and (ii) 36 substations with a total capacity of approximately 1.4 million kVA, 1,870 structure miles of overhead lines, 224 miles of underground conduit and 442 miles of underground conductors in Arkansas.

At December 31, 2003, Enogex and its subsidiaries owned: (i) approximately 8,000 miles of intrastate gas gathering and transportation pipelines in the states of Oklahoma and Texas; (ii) six operating natural gas processing plants with a total inlet capacity of 678 MMcfd, all located in Oklahoma; (iii) 75 percent interest in NOARK, which consists of approximately 931 miles of interstate gas gathering and transportation pipelines, located in eastern Oklahoma and Arkansas; and (iv) two natural gas storage fields in Oklahoma operating at a working gas level of approximately 24.5 Bcf with an approximate withdrawal capability of 650 MMcfd and similar injection capability.

During the three years ended December 31, 2003, the Company's gross property, plant and equipment additions were approximately $603.6 million and gross retirements were approximately $244.1 million. These additions were provided by internally generated funds from operating cash flows, short-term borrowings and permanent financings. The additions during this three-year period amounted to approximately 10.6 percent of total property, plant and equipment at December 31, 2003.

Item 3. Legal Proceedings.

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.

1. The City of Enid, Oklahoma ("Enid") through its City Council, notified OG&E of its intent to purchase OG&E's electric distribution facilities for Enid and to terminate OG&E's franchise to provide electricity within Enid as of June 26, 1998. On August 22, 1997, the City Council of Enid adopted Ordinance No. 97-30, which in essence granted OG&E a new 25-year franchise subject to approval of the electorate of Enid on November 18, 1997. In October 1997, 18 residents of Enid filed a lawsuit against Enid, OG&E and others in the District Court of

Garfield County, State of Oklahoma, Case No. CJ-97-829-01. Plaintiffs seek a declaration holding that (i) the Mayor of Enid and the City Council breached their fiduciary duty to the public and violated Article 10, Section 17 of the Oklahoma Constitution by allegedly "gifting" to OG&E the option the city held to acquire OG&E's electric system when the City Council approved the new franchise by Ordinance No. 97-30; (ii) the subsequent approval of the new franchise by the electorate of the City of Enid at the November 18, 1997, franchise election cannot cure the alleged breach of fiduciary duty or the alleged constitutional violation; (iii) violations of the Oklahoma Open Meetings Act occurred and that such violations render the resolution approving Ordinance No. 97-30 invalid; (iv) OG&E's support of the Enid Citizens' Against the Government Takeover was improper; (v) OG&E has violated the favored nations clause of the existing franchise; and (vi) the City of Enid and OG&E have violated the competitive bidding requirements found at 11 O.S. 35-201, *et seq.* Plaintiffs seek money damages against the Defendants under 62 O.S. 372 and 373. Plaintiffs allege that the action of the City Council in approving the proposed franchise allowed the option to purchase OG&E's property to be transferred to OG&E for inadequate consideration. Plaintiffs demand judgment for treble the value of the property allegedly wrongfully transferred to OG&E. On October 28, 1997, another resident filed a similar lawsuit against OG&E, Enid and the Garfield County Election Board in the District Court of Garfield County, State of Oklahoma, Case No. CJ-97-852-01. However, Case No. CJ-97-852-01 was dismissed without prejudice in December 1997. On December 8, 1997, OG&E filed a Motion to Dismiss Case No. CJ-97-829-01 for failure to state claims upon which relief may be granted. This motion is currently pending. While the Company cannot predict the precise outcome of this proceeding, the Company believes at the present time that this lawsuit is without merit and intends to vigorously defend this case.

2. United States of America ex rel., Jack J. Grynberg v. Enogex Inc., Enogex Services Corporation and OG&E. (United States District Court for the Western District of Oklahoma, Case No. CIV-97-1010-L.) United States of America ex rel., Jack J. Grynberg v. Transok Inc. et al. (United States District Court for the Eastern District of Louisiana, Case No. 97-2089; United States District Court for the Western District of Oklahoma, Case No. 97-1009M.). On June 15, 1999, the Company was served with Plaintiff's complaint, which is a qui tam action under the False Claims Act. Plaintiff Jack J. Grynberg, as individual relator on behalf of the United States Government, alleges: (i) each of the named defendants have improperly or intentionally mismeasured gas (both volume and Btu content) purchased from federal and Indian lands which have resulted in the under-reporting and underpayment of gas royalties owed to the Federal Government; (ii) certain provisions generally found in gas purchase contracts are improper; (iii) transactions by affiliated companies are not arms-length; (iv) excess processing cost deduction; and (v) failure to account for production separated out as a result of gas processing. Grynberg seeks the following damages: (a) additional royalties which he claims should have been paid to the Federal Government, some percentage of which Grynberg, as relator, may be entitled to recover; (b) treble damages; (c) civil penalties; (d) an order requiring defendants to measure the way Grynberg contends is the better way to do so; and (e) interest, costs and attorneys' fees.

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

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

In October 2002, the Court granted the Department of Justice's motion to dismiss certain of Plaintiff's claims and issued an order dismissing Plaintiff's valuation claims against all defendants. Various procedural motions have been filed. 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.

3. *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.

4. *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.

5. A Notice of Enforcement Action ("NOE") by the Texas Natural Resource Conservation Commission (now known as the Texas Commission on Environmental Quality ("TCEQ")) was issued to Products by letter dated July 26, 2002. The NOE relates to the operation of a sulfur recovery unit owned and operated by Belvan at its Crockett County, Texas natural gas processing facility. The TCEQ's proposed fine was approximately $0.1 million and Products is working with the current owner of Belvan to properly respond to the TCEQ, since Products sold its interest in Belvan in March 2002. Products has requested the TCEQ to issue the NOE in the permitted entity's name and is waiting for this correction from the TCEQ. However, Products may retain some liability to the purchaser for any penalties that Belvan might incur from the NOE. Pursuant to the Agreement of Sale and Purchase with the purchaser, Products' liability for any penalties that Belvan might incur from the NOE should not exceed approximately $0.1 million and this amount is fully reserved on Products books.

6. In 1998, Enogex entered into a storage lease agreement (the "Agreement") with 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 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.

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.

7. 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.

8. On October 17, 2002, the City of Jenks, Oklahoma filed a petition in state district court in Tulsa County, Oklahoma against Enogex Inc. seeking damages associated with Enogex's alleged failure to remit a gross receipts tax to the city relating to natural gas sold to an IPP, Green Country Energy, LLC ("Green Country") within the city limits. Based on this claim, the city alleged damages "in excess of $10,000." The city claimed that some of Enogex's pipelines are located within the city's public rights of way, and therefore, based on city ordinance, any sale of natural gas by Enogex to Green Country is subject to a two percent gross receipts tax. The city made an identical claim against two other defendants, Green Country and Exelon Generation Company, LLC, ("Exelon") as the "supplier" of natural gas to Green Country. The city also sought interest on the amount in controversy, as well as its court costs and attorneys' fees. Additionally, the city asserted other claims against Exelon and Green Country pursuant to two other city ordinances. On December 2, 2002, Enogex and the other defendants filed answers denying plaintiff's claims.

On May 8, 2003, the city and Green Country filed a joint motion to approve a settlement. On May 9, 2003, the court entered an order approving the settlement, whereby Green Country agreed to pay the city $3.0 million in lieu of any other taxes or fees that may be assessed by the city for the next 35 years. The claims asserted by the city against Green Country were all dismissed. The city also dismissed the claims against Exelon that were asserted against Green Country. The remaining claim asserted against Enogex and Exelon related to the gross receipts tax was not dismissed; however, Enogex's position is that the settlement between Green Country and the city effectively resolved the gross receipts tax issue. Nonetheless, Enogex cannot guarantee that the city will not continue to pursue the gross receipts tax matter, or other similar matters, against Enogex.

9. In 2000, Enogex entered into long-term firm transportation contracts with an IPP relating to a plant to be built in Wagoner County, Oklahoma. Effective July 1, 2000, the contracts were assigned to Calpine Energy Services, L.P. ("Calpine Energy"). In February 2002, Enogex requested a prepayment from Calpine Energy due to Calpine falling below the contractual creditworthiness criteria. Calpine Energy refused to pay the full monthly demand fees and also refused to make any prepayments as requested. Enogex also made a demand on Calpine Corporation, as guarantor, relating to Calpine Energy's failure to make the required prepayment and demand payments.

In September 2002, Calpine Energy and Calpine Corporation filed a lawsuit against Enogex in connection with this matter. After participating in a court ordered mediation on August 18, 2003, the parties reached a settlement of the pending issues on September 29, 2003. The terms of the settlement obligated Calpine Energy to make a nonrefundable payment to Enogex in the amount of $3.0 million and to maintain a prepayment. Enogex agreed to apply a credit of $1.0 million to the final two months' demand charges under the transportation contract. On October 14, 2003, Enogex received payment of the settlement amount from Calpine Energy. As a result of this settlement, the Company recorded $2.0 million of the settlement payment as revenue in the third quarter of 2003 and this matter is now considered closed.

10. OG&E has been sued by Kaiser-Francis Oil Company in District Court, Blaine County, Oklahoma. This case has been pending for more than 10 years. Plaintiff alleges that OG&E breached the terms of numerous contracts covering approximately 60 wells by failing to

purchase gas from Plaintiff in amounts set forth in the contracts. Plaintiff seeks $20.0 million in take-or-pay damages and $1.8 million in underpayment damages. Over the objection and unsuccessful appeal by OG&E, Plaintiff has been permitted to amend its petition to include a claim based on theories of tort. Specifically, Plaintiff alleges, among other things, that OG&E intentionally and tortuously interfered with contracts by falsifying documents, sponsoring false testimony and putting forward legal defenses, which are known by OG&E to be without merit. If successful, Plaintiff believes that these theories could give Plaintiff a basis to seek punitive damages. OG&E believes that, to the extent Plaintiff were successful on the merits of its claims of OG&E's failure to take gas, these amounts would be recoverable through its regulated electric rates. The claims related to tortuous conduct, which OG&E believes at this time are without merit, would not appear to be properly recoverable in its rates. This lawsuit has been stayed pending the outcome of an appeal that OG&E filed in a similar case brought by Kaiser-Francis in Grady County. In the Grady case, OG&E is appealing a verdict against it in the amount of approximately $8.0 million, including pre-judgment interest and attorneys' fees. While the Company cannot predict the precise outcome of the Grady case or this lawsuit, the Company believes, based on the information known at this time, that this lawsuit will not have a material adverse effect on the Company's consolidated financial position or results of operations.

11. 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 ODEQ, 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 to emit various emissions, with the majority of the sources relating to glycol dehydrators. As previously reported, all but two of the notices were resolved in 2001 and 2002. Enogex has worked with the ODEQ regarding the two remaining notices, the Clinton Gas Plant and the Strong City Compressor Station, as well as two additional notices relating to air permitting issues that were issued by the ODEQ in November 2002 and January 2003, respectively, relating to the Cox City Compressor Station and the Comanche Tap Gas Plant. Enogex has resolved all four of these notices and agreed to pay, in the aggregate, less than $0.1 million in settlement, which included monies for supplemental environmental projects, penalties and certain remediation efforts.

12. On July 31, 2003, representatives of Enogex met with the FERC Staff to discuss resolution of a pending matter that Enogex discovered and brought to the FERC's attention in November 2002 relating to construction by Ozark under its blanket certificate and Enogex under Section 311 authorization. The matter disclosed to the FERC relates to minor construction in 1998 and 1999 that was performed under the reasonable belief that the facilities constituted non-jurisdictional gathering. Accordingly, pre-construction environmental clearances for the FERC-jurisdictional facilities were not obtained and the construction was not reported on blanket certificate and Section 311 construction reports. Upon review, Enogex and Ozark determined that two construction projects should have been treated as FERC-jurisdictional transmission, one under Ozark's blanket certificate and the other pursuant to Enogex's Section 311 authorization. Enogex and Ozark self-reported the non-compliant activities and have cooperated with the FERC's investigation. By order issued December 19, 2003, FERC approved separate consent agreements entered into between FERC and Enogex and Ozark, respectively. Enogex paid a

civil penalty of $80,000, with the additional amount of $15,000 to be suspended if Enogex completes an outreach program informing other industry companies about procedures for obtaining pre-clearance for construction of certain facilities. Ozark paid $20,000 to the FERC to defray the Commission's costs of investigating Ozark's possible violation. This matter is now considered closed.

Item 4. Submission of Matters to a Vote of Security Holders.

None

Executive Officers of the Registrant.

The following persons were Executive Officers of the Registrant as of January 31, 2004:

Name	Age	Title
Steven E. Moore	57	Chairman of the Board, President and Chief Executive Officer
Al M. Strecker	60	Executive Vice President and Chief Operating Officer
Peter B. Delaney	50	Executive Vice President, Finance and Strategic Planning - OGE Energy Corp. and Chief Executive Officer - Enogex Inc.
James R. Hatfield	46	Senior Vice President and Chief Financial Officer
Jack T. Coffman	60	Senior Vice President - Power Supply - OG&E
Steven R. Gerdes	47	Vice President - Utility Operations and Shared Services
Michael G. Davis	54	Vice President - Business Systems and Services
Donald R. Rowlett	46	Vice President and Controller
Deborah S. Fleming	48	Treasurer
Gary D. Huneryager	53	Internal Audit Officer
Carla D. Brockman	44	Corporate Secretary

No family relationship exists between any of the Executive Officers of the Registrant. Messrs. Moore, Strecker, Hatfield, Gerdes, Davis, Rowlett and Huneryager, Ms. Fleming and Ms. Brockman are also officers of OG&E. Each Officer is to hold office until the Board of Directors meeting following the next Annual Meeting of Stockholders, currently scheduled for May 20, 2004.

The business experience of each of the Executive Officers of the Registrant for the past five years is as follows:

Name	Business Experience	
Steven E. Moore	1999 - Present:	Chairman of the Board, President and Chief Executive Officer
Al M. Strecker	1999 - Present:	Executive Vice President and Chief Operating Officer
Peter B. Delaney	2002 - Present:	Executive Vice President, Finance and Strategic Planning - OGE Energy Corp. and Chief Executive Officer - Enogex Inc.
	2001 - 2002:	Principal, PD Energy Advisors (consulting firm)
	1999 - 2001:	Managing Director, UBS Warburg (investment banking firm)

James R. Hatfield	2000 - Present:	Senior Vice President and Chief Financial Officer
	1999 - 2000:	Senior Vice President, Chief Financial Officer and Treasurer
Jack T. Coffman	1999 - Present:	Senior Vice President - Power Supply - OG&E
Steven R. Gerdes	2003 - Present:	Vice President - Utility Operations and Shared Services
	1999 - 2003:	Vice President - Shared Services
Michael G. Davis	2004 - Present	Vice President - Business Systems and Services
	2002 - 2003:	Vice President - Process Management - OG&E
	1999 - 2002:	Vice President - Marketing and Customer Care - OG&E
Donald R. Rowlett	1999 - Present:	Vice President and Controller

Deborah S. Fleming	2003 - Present:	Treasurer
	2000 - 2003:	Assistant Treasurer - Williams Cos. Inc.
	1999 - 2000:	Director of Corporate Finance - Williams Cos. Inc. (energy company)
Gary D. Huneryager	2002 - Present:	Internal Audit Officer
	2001 - 2002:	Assistant Internal Audit Officer
	1999 - 2001:	Service Line Director (Business Process Outsourcing) - Arthur Andersen LLP
Carla D. Brockman	2002 - Present:	Corporate Secretary
	2002:	Assistant Corporate Secretary
	1999 - 2002:	Client Manager - Strategic Planning

PART II

Item 5. Market for Registrant's Common Equity and Related Stockholder Matters.

The Company's Common Stock is listed for trading on the New York and Pacific Stock Exchanges under the ticker symbol "OGE." Quotes may be obtained in daily newspapers where the common stock is listed as "OGE Engy" in the New York Stock Exchange listing table. The following table gives information with respect to price ranges, as reported in *The Wall Street Journal* as New York Stock Exchange Composite Transactions, and dividends paid for the periods shown.

		Price	
2002	Dividend Paid	High	Low
First Quarter	$ 0.3325	$ 24.12	$ 21.28
Second Quarter	0.3325	24.24	21.82
Third Quarter	0.3325	23.29	16.13
Fourth Quarter	0.3325	18.34	13.70

		Price	
2003	**Dividend Paid**	**High**	**Low**
First Quarter	**$ 0.3325**	**$ 19.37**	**$ 15.99**

Second Quarter		**0.3325**	**22.25**	**17.36**
Third Quarter		**0.3325**	**22.75**	**19.50**
Fourth Quarter		**0.3325**	**24.34**	**21.96**

2004		Dividend Paid	Price High	Price Low
First Quarter (through January 31)	$	0.3325	24.50	23.03

The number of record holders of the Company's Common Stock at January 31, 2004, was 31,932. The book value of the Company's Common Stock at January 31, 2004, was $13.81.

Dividend Restrictions

Before the Company can pay any dividends on its common stock, the holders of any of its preferred stock that may be outstanding are entitled to receive their dividends at the respective rates as may be provided for the shares of their series. Currently, there are no shares of preferred stock of the Company outstanding. In addition, the Company may not, except in limited circumstances, declare or pay dividends on its common stock if it has deferred payment of interest on the junior subordinated debentures that were issued in connection with the trust originated preferred securities issued and sold by its subsidiary trust, OGE Energy Capital Trust I. Because the Company is a holding company and conducts all of its operations through

its subsidiaries, the Company's cash flow and ability to pay dividends will be dependent on the earnings and cash flows of its subsidiaries and the distribution or other payment of those earnings to the Company in the form of dividends, or in the form of repayments of loans or advances to it. The Company expects to derive principally all of the funds required by it to enable it to pay dividends on its common stock from dividends paid by OG&E, on OG&E's common stock. The Company's ability to receive dividends on OG&E's common stock is subject to the prior rights of the holders of any OG&E preferred stock that may be outstanding and the covenants of OG&E's certificate of incorporation and its debt instruments limiting the ability of OG&E to pay dividends.

Under OG&E's certificate of incorporation, if any shares of its preferred stock are outstanding, dividends (other than dividends payable in common stock), distributions or acquisitions of OG&E common stock:

- may not exceed 50 percent of net income for a prior 12-month period, after deducting dividends on any preferred stock during the period, if the sum of the capital represented by the common stock, premiums on capital stock (restricted to premiums on common stock only by SEC orders), and surplus accounts is less than 20 percent of capitalization;
- may not exceed 75 percent of net income for such 12-month period, as adjusted if this capitalization ratio is 20 percent or more, but less than 25 percent; and
- if this capitalization ratio exceeds 25 percent, dividends, distributions or acquisitions may not reduce the ratio to less than 25 percent except to the extent permitted by the provisions described in the above two bullet points.

Currently, no shares of OG&E preferred stock are outstanding and no portion of the retained earnings of OG&E is presently restricted by this provision. OG&E's certificate of incorporation further provides that no dividend may be declared or paid on the OG&E common stock until all amounts required to be paid or set aside for any sinking fund for the redemption or purchase of OG&E cumulative preferred stock, par value $25 per share, have been paid or set aside.

Item 6. Selected Financial Data.

HISTORICAL DATA

	2003	2002	2001	2000	1999
SELECTED FINANCIAL DATA *(In millions, except per share data)*					
Operating revenues	**$3,779.0**	$3,023.9	$3,064.4	$3,184.4	$2,106.7
Cost of goods sold	**2,846.0**	2,120.3	2,185.6	2,275.3	1,260.5
Gross margin on revenues	**933.0**	903.6	878.8	909.1	846.2
Other operating expenses	**626.1**	667.9	607.9	574.5	521.4
Operating income	**306.9**	235.7	270.9	334.6	324.8
Other income	**8.1**	3.7	3.1	4.2	2.7
Other expense	**9.0**	4.7	4.2	3.6	2.7
Net interest expense	**96.7**	109.1	123.0	129.4	97.5

Income tax expense	**73.7**	44.6	52.9	72.0	87.3
Income from continuing operations	**135.6**	81.0	93.9	133.8	140.0
Income (loss) from discontinued operations, net of tax	**(0.4)**	9.8	6.7	13.2	11.3
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	$ 147.0	$ 151.3
Basic earnings (loss) per average common share					
Income from continuing operations	**$ 1.66**	$ 1.04	$ 1.20	$ 1.72	$ 1.80
Income from discontinued operations, net of tax	---	0.12	0.09	0.17	0.14
Loss from cumulative effect of accounting change, net of tax	**(0.07)**	---	---	---	---
Net income	**$ 1.59**	$ 1.16	$ 1.29	$ 1.89	$ 1.94
Diluted earnings (loss) per average common share					
Income from continuing operations	**$ 1.65**	$ 1.04	$ 1.20	$ 1.72	$ 1.80
Income from discontinued operations, net of tax	---	0.12	0.09	0.17	0.14
Loss from cumulative effect of accounting change, net of tax	**(0.07)**	---	---	---	---
Net income	**$ 1.58**	$ 1.16	$ 1.29	$ 1.89	$ 1.94
Dividends declared per share	**$ 1.33**	$ 1.33	$ 1.33	$ 1.33	$ 1.33

HISTORICAL DATA (Continued)

	2003	2002	2001	2000	1999
SELECTED FINANCIAL DATA *(In millions, except per share data)*					
Long-term debt	**$1,436.1**	$1,501.9	$1,526.3	$1,648.5	$1,140.5
Total assets	**$4,584.7**	$4,264.9	$4,118.0	$4,444.6	$4,043.0
CAPITALIZATION RATIOS (A)					
Stockholders' equity	**45.56%**	39.58%	40.54%	39.23%	47.20%
Long-term debt	**54.44%**	60.42%	59.46%	60.77%	52.80%
RATIO OF EARNINGS TO FIXED CHARGES (B)					
Ratio of earnings to fixed charges	**3.06**	2.08	2.10	2.45	3.12

(A) Capitalization ratios = [Stockholders' equity / (Stockholders' equity + Long-term debt)] and [Long-term debt / (Stockholders' equity + Long-term debt)].

(B) For purposes of computing the ratio of earnings to fixed charges, (1) earnings consist of income from continuing operations plus fixed charges, federal and state income taxes, deferred income taxes and investment tax credits (net); and (2) fixed charges consist of interest on long-term debt, related amortization, interest on short-term borrowings and a calculated portion of rents considered to be interest.

Item 7. Management's Discussion and Analysis of Financial Condition and 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.

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

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", "objective", "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

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

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

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

$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 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

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.

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.

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

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

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

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.

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.

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

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.

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

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

$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 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

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

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.

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

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

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

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.

	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.

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,

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.

	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

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

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

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

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 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.

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

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 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

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

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

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.

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.

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

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

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.

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 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.

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.

Item 7A. 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.

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

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

Item 8. 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.

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.

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.

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.

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.

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.

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.

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

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

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

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
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)

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

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

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 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

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

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**		---		---

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%

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.

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.

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

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:

		Options Outstanding		Options Exercisable	
Range of Exercise Prices	Weighted-Average Remaining Contractual Life	Number Outstanding	Weighted-Average Exercise Price	Number Outstanding	Weighted-Average Exercise Price
$16.69 - $22.70	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 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

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

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.

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.

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

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") or 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.

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

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

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.

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

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

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.

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

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

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

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.

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

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.

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

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

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.

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 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

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

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

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

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

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

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:

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

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	/s/ Al M. Strecker
Steven E. Moore, Chairman of the Board, President and Chief Executive Officer	Al M. Strecker, Executive Vice President and Chief Operating Officer
/s/ Peter B. Delaney	/s/ James R. Hatfield
Peter B. Delaney, Executive Vice President, Finance and Strategic Planning - OGE Energy Corp. and Chief Executive Officer - Enogex Inc.	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

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

Item 9. Changes In and Disagreements with Accountants on Accounting and Financial Disclosure.

None

Item 9A. Controls and Procedures.

The Company maintains a set of disclosure controls and procedures designed to ensure that information required to be disclosed by the Company in reports that it files or submits under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission rules and forms. As of the end of the period covered by this report, based on an evaluation carried out under the supervision and with the participation of the Company's management, including the Chief Executive Officer ("CEO") and Chief Financial Officer ("CFO"), of the effectiveness of the Company's disclosure

controls and procedures, the CEO and CFO have concluded that the Company's disclosure controls and procedures are effective.

Subsequent to the date of their evaluation, there have been no significant changes in the Company's internal controls or in other factors that could significantly affect these controls.

No change in the Company's internal control over financial reporting has occurred during the Company's most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, the Company's internal control over financial reporting.

PART III

Item 10. Directors and Executive Officers of the Registrant.

CODE OF ETHICS POLICY

The Company maintains a code of ethics for our chief executive officer and senior financial officers, including the chief financial officer and chief accounting officer, which is available for public viewing on the Company's web site address *www.oge.com* under the heading "Investors", "Corporate Governance." The Company intends to satisfy the disclosure requirements under Item 10 of Form 8-K regarding an amendment to, or waiver from, a provision of the code of ethics by posting such information on its web site at the location specified above.

Item 11. Executive Compensation.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters.

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 (A)	2,871,802	$21.63	2,700,000 (B)
Equity Compensation Plans Not Approved by Shareowners	0	N/A	N/A

(A) 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.
(B) Awards under the Stock Incentive Plan can take the form of stock options, stock appreciation rights, restricted stock or performance units.
N/A – not applicable

Item 13. Certain Relationships and Related Transactions.

Item 14. Principal Accountant Fees and Services.

Items 10, 11, 12, 13 and 14 (other than Item 10 information regarding the Code of Ethics and Item 12 information required by Item 201(d) of Regulation S-K) are omitted pursuant to General Instruction G of Form 10-K, since the Company will file copies of a definitive proxy statement with the Securities and Exchange Commission on or about March 30, 2004. Such proxy statement is incorporated herein by reference. In accordance with General Instruction G of Form 10-K, the information required by Item 10 relating to Executive Officers has been included in Part I, Item 4, of this Form 10-K.

PART IV

Item 15. Exhibits, Financial Statement Schedules and Reports on Form 8-K.

(a) 1. Financial Statements

The following consolidated financial statements and supplementary data are included in Part II, Item 8 of this Report:

- Consolidated Balance Sheets at December 31, 2003 and 2002
- Consolidated Statements of Capitalization at December 31, 2003 and 2002
- Consolidated Statements of Income for the years ended December 31, 2003, 2002 and 2001
- Consolidated Statements of Retained Earnings for the years ended December 31, 2003, 2002 and 2001
- Consolidated Statements of Comprehensive Income for the years ended December 31, 2003, 2002 and 2001
- Consolidated Statements of Cash Flows for the years ended December 31, 2003, 2002 and 2001
- Notes to Consolidated Financial Statements

- Report of Independent Auditors
- Report of Management

Supplementary Data

- Interim Consolidated Financial Information

All other schedules have been omitted since the required information is not applicable or is not material, or because the information required is included in the respective consolidated financial statements or notes thereto.

3. Exhibits

Exhibit No.	**Description**
2.01	Purchase Agreement, dated as of May 14, 1999, by and between Tejas Gas, LLC and Enogex Inc. (Filed as Exhibit 2.01 to OGE Energy's Form 10-Q for the quarter ended June 30, 1999 (File No. 1-12579) and incorporated by reference herein)
2.02	Asset Purchase Agreement, dated as of August 18, 2003 by and between OG&E and NRG McClain LLC. (Certain exhibits and schedules were omitted and registrant agrees to furnish supplementally a copy of such omitted exhibits and schedules to the Commission upon request) (Filed as Exhibit 2.01 to OGE Energy's Form 8-K dated August 18, 2003 (File No. 1-12579) and incorporated by reference herein)
2.03	Amendment No. 1 to Asset Purchase Agreement, dated as of October 22, 2003 by and between OG&E and NRG McClain LLC.
2.04	Amendment No. 2 to Asset Purchase Agreement, dated as of October 27, 2003 by and between OG&E and NRG McClain LLC.
2.05	Amendment No. 3 to Asset Purchase Agreement, dated as of November 25, 2003 by and between OG&E and NRG McClain LLC.
2.06	Amendment No. 4 to Asset Purchase Agreement, dated as of January 28, 2004 by and between OG&E and NRG McClain LLC.
2.07	Amendment No. 5 to Asset Purchase Agreement, dated as of February 13, 2004 by and between OG&E and NRG McClain LLC.
3.01	Copy of Restated Certificate of Incorporation. (Filed as Exhibit 3.01 to OGE Energy's Form 10-K for the year ended December 31, 1996 (File No. 1-12579) and incorporated by reference herein)
3.02	By-laws. (Filed as Exhibit 3.02 to OGE Energy's Form 10-K for the year ended December 31, 1996 (File No. 1-12579) and incorporated by reference herein)
4.01	Copy of Trust Indenture dated October 1, 1995, from OG&E to Boatmen's First National Bank of Oklahoma, Trustee. (Filed as Exhibit 4.29 to Registration Statement No. 33-61821 and incorporated by reference herein)
4.02	Copy of Supplemental Trust Indenture No. 1 dated October 16, 1995, being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 4.01 to OG&E's Form 8-K dated October 23, 1995 (File No. 1-1097) and incorporated by reference herein)

4.03	Supplemental Indenture No. 2, dated as of July 1, 1997, being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 4.01 to OG&E's Form 8-K filed on July 17, 1997 (File No. 1-1097) and incorporated by reference herein)
4.04	Supplemental Indenture No. 3, dated as of April 1, 1998, being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 4.01 to OG&E's Form 8-K filed on April 16, 1998 (File No. 1-1097) and incorporated by reference herein)

4.05 Supplemental Indenture No. 4, dated as of October 15, 2000, being a supplement instrument to Exhibit 4.01 hereto. (Filed as Exhibit 4.02 to OG&E's Form 8-K filed on October 20, 2000 (File No. 1-1097) and incorporated by reference herein)

10.01 Coal Supply Agreement dated March 1, 1973, between OG&E and Atlantic Richfield Company. (Filed as Exhibit 5.19 to Registration Statement No. 2-59887 and incorporated by reference herein)

10.02 Amendment dated April 1, 1976, to Coal Supply Agreement dated March 1, 1973, between OG&E and Atlantic Richfield Company, together with related correspondence. (Filed as Exhibit 5.21 to Registration Statement No. 2-59887 and incorporated by reference herein)

10.03 Second Amendment dated March 1, 1978, to Coal Supply Agreement dated March 1, 1973, between OG&E and Atlantic Richfield Company. (Filed as Exhibit 5.28 to Registration Statement No. 2-62208 and incorporated by reference herein)

10.04 Amendment dated June 27, 1990, between OG&E and Thunder Basin Coal Company, to Coal Supply Agreement dated March 1, 1973, between OG&E and Atlantic Richfield Company. (Filed as Exhibit 10.04 to OG&E's Form 10-K for the year ended December 31, 1994 (File No. 1-1097) and incorporated by reference herein) [Confidential Treatment has been requested for certain portions of this exhibit.]

10.05 Form of Change of Control Agreement for Officers of the Company and OG&E. (Filed as Exhibit 10.07 to OGE Energy's Form 10-K for the year ended December 31, 1996 (File No. 1-12579) and incorporated by reference herein)

10.06 Company's 1998 Stock Incentive Plan. (Filed as Exhibit 10.07 to OGE Energy's Form 10-K for the year ended December 31, 1998 (File No. 1-12579) and incorporated by reference herein)

10.07 Company's 2003 Stock Incentive Plan. (Filed as Annex A to OGE Energy's Proxy Statement for the 2003 Annual Meeting of Shareowners (File No. 1-12579) and incorporated by reference herein)

10.08 OGE Energy Corp. Restoration of Retirement Income Plan, as amended by Amendments No. 1 and No. 2. (Filed as Exhibit 10.12 to OGE Energy's Form 10-K for the year

ended December 31, 1996 (File No.1-12579) and incorporated by reference herein)

10.09 Amendment No. 3 to the OGE Energy Corp. Restoration of Retirement Income Plan. (Filed as Exhibit 10.13 to OGE Energy's Form 10-K for the year ended December 31, 2000 (File No. 1-12579) and incorporated by reference herein)

10.10 Amendment No. 4 to the OGE Energy Corp. Restoration of Retirement Income Plan. (Filed as Exhibit 10.14 to OGE Energy's Form 10-K for the year ended December 31, 2000 (File No. 1-12579) and incorporated by reference herein)

10.11 OGE Energy Corp. Supplemental Executive Retirement Plan, as amended. (Filed as Exhibit 10.15 to OGE Energy's Form 10-K for the year ended December 31, 1996 (File No. 1-12579) and incorporated by reference herein)

10.12 Company's 2003 Annual Incentive Compensation Plan. (Filed as Annex B to OGE Energy's Proxy Statement for the 2003 Annual Meeting of Shareowners (File No. 1-12579) and incorporated by reference herein)

10.13 OGE EnergyEnergy Corp. Deferred Compensation Plan and Amendment No. 1 to OGE Energy Corp. Deferred Compensation Plan. (Filed as Exhibit 10.12 to OGE Energy's Form 10-K for the year ended December 31, 2002 (File No. 1-12579) and incorporated by reference herein)

10.14 Copy of Amended and Restated Rights Agreement, dated as of October 10, 2000 between OGE Energy Corp. and Chase Mellon Shareholder Services, LLC, as Rights Agent. (Filed as Exhibit 4.1 to OGE Energy's Form 8-K filed on November 1, 2000 (File No. 1-12579) and incorporated by reference herein)

10.15 Copy of Settlement Agreement with Oklahoma Corporation Commission Staff, the Oklahoma Attorney General and others relating to OG&E's rate case. (Filed as Exhibit 99.02 to OGE Energy's Form 10-Q for the quarter ended September 30, 2002 (File No. 1-12579) and incorporated by reference herein)

10.16 Copy of Employment Agreement with Peter B. Delaney. (Filed as Exhibit 10.15 to OGE Energy's Form 10-K for the year ended December 31, 2002 (File No. 1-12579) and incorporated by reference herein)

10.17 Copy of Severance Agreement with Roger A. Farrell. (Filed as Exhibit 10.16 to OGE Energy's Form 10-K for the year ended December 31, 2002 (File No. 1-12579) and incorporated by reference herein)

10.18 Revolving Note Agreement as amended by Amendments No. 1 and No. 2, dated April 6, 2002 between OGE Energy Corp. and Bank of Oklahoma, N.A. (Filed as Exhibit 10.19 to OGE Energy's Form 10-K for the year ended December 31, 2002 (File No. 1-12579) and incorporated by reference herein)

10.19 Revolving Note Agreement as amended by Amendment No. 3, dated April 6, 2003 between OGE Energy Corp. and Bank of Oklahoma, N.A. (Filed as Exhibit 10.01 to OGE Energy's Form 10-Q for the quarter ended March 31, 2003 (File No. 1-12579) and incorporated by reference herein)

10.20 Transportation Precedent Agreement dated October 18, 2002 between Enogex Inc. and Colorado Interstate Gas Company. (Filed as Exhibit 10.02 to OGE Energy's Form 10-Q for the quarter ended March 31, 2003 (File No. 1-12579) and incorporated by reference herein)

10.21 Credit Agreement dated June 26, 2003 between OG&E, Bank One, NA, Wachovia Bank, National Association, Cobank, ACB and LaSalle Bank National Association. (Filed as Exhibit 10.01 to OGE Energy's Form 10-Q for the quarter ended June 30, 2003 (File No. 1-12579) and incorporated by reference herein)

10.22 Credit Agreement dated December 11, 2003 between OGE Energy Corp. and Bank One, NA, Wachovia Bank, National Association, Commerzbank AG, Citibank, N.A. and the Bank of New York.

10.23 Amended and Restated Facility Operating Agreement dated December 17, 2003 between OG&E and the Oklahoma Municipal Power Authority.

10.24 Amended and Restated Ownership and Operation Agreement dated December 17, 2003 between OG&E and the Oklahoma Municipal Power Authority.

12.01 Calculation of Ratio of Earnings to Fixed Charges.

16.01 Letter of Arthur Andersen LLP regarding change in certifying accountant. (Filed as Exhibit 16.01 to OGE Energy's Form 8-K filed on May 21, 2002 (File No. 1-12579) and incorporated by reference herein)

21.01 Subsidiaries of the Registrant.

23.01 Consent of Ernst & Young LLP.

24.01 Power of Attorney.

31.01 Certifications Pursuant to Rule 13a-15(e)/15d-15(e) As Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

32.01 Certification Pursuant to 18 U.S.C. Section 1350 As Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

99.01 Cautionary Statement for Purposes of the "Safe Harbor" Provisions of the Private Securities Litigation Reform Act of 1995.

Executive Compensation Plans and Arrangements

10.05 Form of Change of Control Agreement for Officers of the Company and OG&E. (Filed as Exhibit 10.07 to OGE Energy's Form 10-K for the year ended December 31, 1996 (File No. 1-12579) and incorporated by reference herein)

10.06 Company's 1998 Stock Incentive Plan. (Filed as Exhibit 10.07 to OGE Energy's Form 10-K for the year ended December 31, 1998 (File No. 1-12579) and incorporated by reference herein)

10.07 Company's 2003 Stock Incentive Plan. (Filed as Annex A to OGE Energy's Proxy Statement for the 2003 Annual Meeting of Shareowners (File No. 1-12579) and incorporated by reference herein)

10.08 OGE Energy Corp. Restoration of Retirement Income Plan, as amended by Amendments No. 1 and No. 2. (Filed as Exhibit 10.12 to OGE Energy's Form 10-K for the year ended December 31, 1996 (File No.1-12579) and incorporated by reference herein)

10.09 Amendment No. 3 to the OGE Energy Corp. Restoration of Retirement Income Plan. (Filed as Exhibit 10.13 to OGE Energy's Form 10-K for the year ended December 31, 2000 (File No. 1-12579) and incorporated by reference herein)

10.10 Amendment No. 4 to the OGE Energy Corp. Restoration of Retirement Income Plan. (Filed as Exhibit 10.14 to OGE Energy's Form 10-K for the year ended December 31, 2000 (File No. 1-12579) and incorporated by reference herein)

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(b) Reports on Form 8-K

The Company filed a Current Report on Form 8-K on October 31, 2003 to report that OG&E filed a request with the OCC to increase its rates by approximately $91 million annually.

The Company filed a Current Report on Form 8-K on November 12, 2003 to report its consolidated results of operations and financial condition for the third quarter of 2003.

The Company filed a Current Report on Form 8-K on December 2, 2003 to report that OG&E and NRG McClain LLC agreed to amend the asset purchase agreement to extend the optional termination date of the asset purchase agreement.

The Company filed a Current Report on Form 8-K on December 18, 2003 to report that the FERC ordered a hearing regarding the acquisition of the NRG McClain power plant by OG&E.

The Company filed a Current Report on Form 8-K on January 16, 2004 to report that OG&E withdrew its request for a $91 million rate increase.

The Company filed a Current Report on Form 8-K on January 28, 2004 to report its consolidated results of operations and financial condition for the fourth quarter and year ended December 31, 2003.

OGE ENERGY CORP.

SCHEDULE II — Valuation and Qualifying Accounts

Description	Balance at Beginning of Period	Additions: Charged to Costs and Expenses	Additions: Charged to Other Accounts	Deductions	Balance at End of Period
			(In millions)		
Year Ended December 31, 2001					
Reserve for Uncollectible Accounts	$ 6.7	$ 18.5	$ ---	$ 15.5 (A)	$ 9.7
Year Ended December 31, 2002					

Reserve for Uncollectible Accounts	$ 9.7	$ 11.0	$ 3.7	$ 10.8 (A)	$ 13.6
Year Ended December 31, 2003					
Reserve for Uncollectible Accounts	$ 13.6	$ 2.0	$ ---	$ 11.4 (A)	$ 4.2

(A) Uncollectible accounts receivable written off, net of recoveries.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, as amended, the Registrant has duly caused this Report to be signed on its behalf by the undersigned, thereunto duly authorized, in the City of Oklahoma City, and State of Oklahoma on the 8th day of March, 2004.

OGE ENERGY CORP.
(Registrant)

By /s/ Steven E. Moore

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

Pursuant to the requirements of the Securities Exchange Act of 1934, as amended, this Report has been signed below by the following persons in the capacities and on the dates indicated.

Signature	Title	Date
/ s / Steven E. Moore Steven E. Moore	Principal Executive Officer and Director;	March 8, 2004
/ s / James R. Hatfield James R. Hatfield	Principal Financial Officer; and	March 8, 2004
/ s / Donald R. Rowlett Donald R. Rowlett	Principal Accounting Officer.	March 8, 2004
Herbert H. Champlin	Director;	
Luke R. Corbett	Director;	
William E. Durrett	Director;	
Martha W. Griffin	Director;	
John D. Groendyke	Director;	
Robert Kelley	Director;	
Ronald H. White, M.D.	Director; and	
J. D. Williams	Director.	
/ s / Steven E. Moore By Steven E. Moore (attorney-in-fact)		March 8, 2004

Exhibit Index

Exhibit No.	**Description**
2.01	Purchase Agreement, dated as of May 14, 1999, by and between Tejas Gas, LLC and Enogex Inc.

(Filed as Exhibit 2.01 to OGE Energy's Form 10-Q for the quarter ended June 30, 1999 (File No. 1-12579) and incorporated by reference herein)

2.02	Asset Purchase Agreement, dated as of August 18, 2003 by and between OG&E and NRG McClain LLC. (Certain exhibits and schedules were omitted and registrant agrees to furnish supplementally a copy of such omitted exhibits and schedules to the Commission upon request) (Filed as Exhibit 2.01 to OGE Energy's Form 8-K dated August 18, 2003 (File No. 1-12579) and incorporated by reference herein)	
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2.04	Amendment No. 2 to Asset Purchase Agreement, dated as of October 27, 2003 by and between OG&E and NRG McClain LLC.	
2.05	Amendment No. 3 to Asset Purchase Agreement, dated as of November 25, 2003 by and between OG&E and NRG McClain LLC.	
2.06	Amendment No. 4 to Asset Purchase Agreement, dated as of January 28, 2004 by and between OG&E and NRG McClain LLC.	
2.07	Amendment No. 5 to Asset Purchase Agreement, dated as of February 13, 2004 by and between OG&E and NRG McClain LLC.	
3.01	Copy of	Restated Certificate of Incorporation. (Filed as Exhibit 3.01 to OGE Energy's Form 10-K for the year ended December 31, 1996 (File No. 1-12579) and incorporated by reference herein)
3.02	By-laws.	(Filed as Exhibit 3.02 to OGE Energy's Form 10-K for the year ended December 31, 1996 (File No. 1-12579) and incorporated by reference herein)
4.01	Copy of	Trust Indenture dated October 1, 1995, from OG&E to Boatmen's First National Bank of Oklahoma, Trustee. (Filed as Exhibit 4.29 to Registration Statement No. 33-61821 and incorporated by reference herein)
4.02	Copy of	Supplemental Trust Indenture No. 1 dated October 16, 1995, being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 4.01 to OG&E's Form 8-K dated October 23, 1995 (File No. 1-1097) and incorporated by reference herein)
4.03	Supplemental Indenture No. 2, dated as of July 1, 1997, being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 4.01 to OG&E's Form 8-K filed on July 17, 1997 (File No. 1-1097) and incorporated by reference herein)	
4.04	Supplemental Indenture No. 3, dated as of April 1, 1998, being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 4.01 to OG&E's Form 8-K filed on April 16, 1998 (File No. 1-1097) and incorporated by reference herein)	
4.05	Supplemental Indenture No. 4, dated as of October 15, 2000, being a supplement instrument to Exhibit 4.01 hereto. (Filed as Exhibit 4.02 to OG&E's Form 8-K filed on October 20, 2000 (File No. 1-1097) and incorporated by reference herein)	
10.01	Coal Supply Agreement dated March 1, 1973, between OG&E and Atlantic Richfield Company. (Filed as Exhibit 5.19 to Registration Statement No. 2-59887 and incorporated by reference herein)	
10.02	Amendment dated April 1, 1976, to Coal Supply Agreement dated March 1, 1973, between OG&E and Atlantic Richfield Company, together with related correspondence. (Filed as Exhibit 5.21 to Registration Statement No. 2-59887 and incorporated by reference herein)	
10.03	Second Amendment dated March 1, 1978, to Coal Supply Agreement dated March 1, 1973, between OG&E and Atlantic Richfield Company. (Filed as Exhibit 5.28 to Registration Statement No. 2-62208 and incorporated by reference herein)	
10.04	Amendment dated June 27, 1990, between OG&E and Thunder Basin Coal Company, to Coal Supply Agreement dated March 1, 1973, between OG&E and Atlantic Richfield Company. (Filed as Exhibit 10.04 to OG&E's Form 10-K for the year ended December 31, 1994 (File No. 1-1097) and incorporated by reference herein) [Confidential Treatment has been requested for certain portions of this exhibit.]	
10.05	Form of	Change of Control Agreement for Officers of the Company and OG&E. (Filed as Exhibit 10.07 to OGE Energy's Form 10-K for the year ended December 31, 1996 (File No. 1-12579) and incorporated by reference herein)
10.06	Company's 1998 Stock Incentive Plan. (Filed as Exhibit 10.07 to OGE Energy's Form 10-K for the	

year ended December 31, 1998 (File No. 1-12579) and incorporated by reference herein)

10.07 Company's 2003 Stock Incentive Plan. (Filed as Annex A to OGE Energy's Proxy Statement for the 2003 Annual Meeting of Shareowners (File No. 1-12579) and incorporated by reference herein)

10.08 OGE Energy Corp. Restoration of Retirement Income Plan, as amended by Amendments No. 1 and No. 2. (Filed as Exhibit 10.12 to OGE Energy's Form 10-K for the year ended December 31, 1996 (File No.1-12579) and incorporated by reference herein)

10.09 Amendment No. 3 to the OGE Energy Corp. Restoration of Retirement Income Plan. (Filed as Exhibit 10.13 to OGE Energy's Form 10-K for the year ended December 31, 2000 (File No. 1-12579) and incorporated by reference herein)

10.10 Amendment No. 4 to the OGE Energy Corp. Restoration of Retirement Income Plan. (Filed as Exhibit 10.14 to OGE Energy's Form 10-K for the year ended December 31, 2000 (File No. 1-12579) and incorporated by reference herein)

10.11 OGE Energy Corp. Supplemental Executive Retirement Plan, as amended. (Filed as Exhibit 10.15 to OGE Energy's Form 10-K for the year ended December 31, 1996 (File No. 1-12579) and incorporated by reference herein)

10.12 Company's 2003 Annual Incentive Compensation Plan. (Filed as Annex B to OGE Energy's Proxy Statement for the 2003 Annual Meeting of Shareowners (File No. 1-12579) and incorporated by reference herein)

10.13 OGE Energy Energy Corp. Deferred Compensation Plan and Amendment No. 1 to OGE Energy Corp. Deferred Compensation Plan. (Filed as Exhibit 10.12 to OGE Energy's Form 10-K for the year ended December 31, 2002 (File No. 1-12579) and incorporated by reference herein)

10.14 Copy of Amended and Restated Rights Agreement, dated as of October 10, 2000 between OGE Energy Corp. and Chase Mellon Shareholder Services, LLC, as Rights Agent. (Filed as Exhibit 4.1 to OGE Energy's Form 8-K filed on November 1, 2000 (File No. 1-12579) and incorporated by reference herein)

10.15 Copy of Settlement Agreement with Oklahoma Corporation Commission Staff, the Oklahoma Attorney General and others relating to OG&E's rate case. (Filed as Exhibit 99.02 to OGE Energy's Form 10-Q for the quarter ended September 30, 2002 (File No. 1-12579) and incorporated by reference herein)

10.16 Copy of Employment Agreement with Peter B. Delaney. (Filed as Exhibit 10.15 to OGE Energy's Form 10-K for the year ended December 31, 2002 (File No. 1-12579) and incorporated by reference herein)

10.17 Copy of Severance Agreement with Roger A. Farrell. (Filed as Exhibit 10.16 to OGE Energy's Form 10-K for the year ended December 31, 2002 (File No. 1-12579) and incorporated by reference herein)

10.18 Revolving Note Agreement as amended by Amendments No. 1 and No. 2, dated April 6, 2002 between OGE Energy Corp. and Bank of Oklahoma, N.A. (Filed as Exhibit 10.19 to OGE Energy's Form 10-K for the year ended December 31, 2002 (File No. 1-12579) and incorporated by reference herein)

10.19 Revolving Note Agreement as amended by Amendment No. 3, dated April 6, 2003 between OGE Energy Corp. and Bank of Oklahoma, N.A. (Filed as Exhibit 10.01 to OGE Energy's Form 10-Q for the quarter ended March 31, 2003 (File No. 1-12579) and incorporated by reference herein)

10.20 Transportation Precedent Agreement dated October 18, 2002 between Enogex Inc. and Colorado Interstate Gas Company. (Filed as Exhibit 10.02 to OGE Energy's Form 10-Q for the quarter ended March 31, 2003 (File No. 1-12579) and incorporated by reference herein)

10.21 Credit Agreement dated June 26, 2003 between OG&E, Bank One, NA, Wachovia Bank, National Association, Cobank, ACB and LaSalle Bank National Association. (Filed as Exhibit 10.01 to OGE Energy's Form 10-Q for the quarter ended June 30, 2003 (File No. 1-12579) and incorporated by reference herein)

10.22 Credit Agreement dated December 11, 2003 between OGE Energy Corp. and Bank One, NA, Wachovia Bank, National Association, Commerzbank AG, Citibank, N.A. and the Bank of New York.

10.23 Amended and Restated Facility Operating Agreement dated December 17, 2003 between OG&E and the Oklahoma Municipal Power Authority.

10.24 Amended and Restated Ownership and Operation Agreement dated December 17, 2003 between OG&E and the Oklahoma Municipal Power Authority.

12.01 Calculation of Ratio of Earnings to Fixed Charges.

16.01 Letter of Arthur Andersen LLP regarding change in certifying accountant. (Filed as Exhibit 16.01 to OGE Energy's Form 8-K filed on May 21, 2002 (File No. 1-12579) and incorporated by reference herein)

21.01 Subsidiaries of the Registrant.

23.01 Consent of Ernst & Young LLP.

24.01 Power of Attorney.

31.01 Certifications Pursuant to Rule 13a-15(e)/15d-15(e) As Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

32.01 Certification Pursuant to 18 U.S.C. Section 1350 As Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

99.01 Cautionary Statement for Purposes of the "Safe Harbor" Provisions of the Private Securities Litigation Reform Act of 1995.

Exhibit 2.03

AMENDMENT NO. 1 TO ASSET PURCHASE AGREEMENT

THIS AMENDMENT NO. 1 TO ASSET PURCHASE AGREEMENT (this "Amendment"), dated as of October 22, 2003, is made by **NRG McCLAIN LLC,** a Delaware limited liability company ("Seller"), and **OKLAHOMA GAS AND ELECTRIC COMPANY,** an Oklahoma corporation ("Buyer").

RECITALS

A. Seller and Buyer entered into an Asset Purchase Agreement, dated as of August 18, 2003 (the "Agreement"; capitalized terms used but not defined in this Amendment have the meanings ascribed to such terms in the Agreement).

B. Seller is the debtor and debtor in possession in Case No. 03-15205(PCB) (the "Case") under Chapter 11 of the United States Bankruptcy Code currently pending in the United States Bankruptcy Court for the Southern District of New York (the "Bankruptcy Court"), which Case is being jointly administered with several other affiliated Chapter 11 cases under Case No. 03-13204(PCB).

C. Seller and Buyer wish to amend the Agreement to add one contract to Schedule 2.2(j) to the Agreement.

NOW, THEREFORE, in consideration of the premises and for other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the parties hereto agree to amend the Agreement as follows:

ARTICLE I
Amendment to Agreement

SECTION 1.1 Addition to Schedule 2.2(j). Schedule 2.2(j) of the Agreement is hereby amended to add thereto the following item:

"48. Letter agreement, dated November 1, 2002, between Merrill Lynch & Co. and Seller."

ARTICLE II
Miscellaneous

SECTION 2.1 References to the Agreement. (a) Each reference in the Agreement to *"this Agreement," "hereunder," "herein"* or words of like import shall mean and be a reference to the Agreement as amended and affected hereby.

(b) Each reference in the other Transaction Documents to the Agreement shall mean and be a reference to the Agreement, as amended and affected hereby.

SECTION 2.2. Effectiveness. This Amendment shall become effective upon the satisfaction, or waiver in writing by Seller and Buyer, of the following conditions:

(a) Each of Seller and Buyer shall have executed this Amendment;

(b) WestLB AG, as Agent (the "Agent") for the Lenders parties to that Omnibus Restructuring and Consent Agreement dated as of August 18, 2003 (the "ORCA"), by and among Seller, the Agent, the Lenders and the affiliates of Seller parties thereto, shall have executed a copy of this Amendment for the limited purpose of evidencing its consent to this Amendment in accordance with the provisions of the ORCA.

(c) An order of the Court approving this Amendment shall have been entered.

SECTION 2.3 Ratification. Each of Buyer and Seller acknowledges and ratifies the Agreement and the other Transaction Documents, as amended and affected hereby, and agrees and acknowledges that all the terms thereof as amended and affected hereby, (a) are hereby brought forward for the benefit of the parties thereto, and (b) shall remain in full force and effect.

SECTION 2.4 Governing Law. This Amendment shall be governed by and construed in accordance with the laws of the State of New York without giving effect to any choice or conflict of law provision or rule (whether of the State of New York or any other jurisdiction) that would cause the application of the laws of any jurisdiction other than the State of New York, except to the extent preempted by federal bankruptcy laws.

SECTION 2.5 Headings and Definitions. The Section and Article headings contained in this Amendment are inserted for convenience of reference only and shall not affect the meaning or interpretation of this Amendment. All references to Sections or Articles contained herein mean Sections or Articles of this Amendment or the Agreement, as indicated, unless otherwise stated. All defined terms and phrases herein are equally applicable to both the singular and plural forms of such terms.

SECTION 2.6 Counterparts. This Amendment may be executed in one or more counterparts, all of which shall be considered one and the same agreement, and shall become effective when one or more counterparts have been signed by each of the parties and delivered to the other parties.

SECTION 2.7 Electronic Signatures.

(a) Notwithstanding the Electronic Signatures in Global and National Commerce Act (15 U.S.C. Sec. 7001 *et seq.*), the Uniform Electronic Transactions Act, or any other Law relating to or enabling the creation, execution, delivery, or recordation of any contract or signature by electronic means, and notwithstanding any course of conduct engaged in by the Parties, no Party shall be deemed to have executed this Amendment unless and until such Party shall have executed this Amendment on paper by a handwritten original signature or any other symbol executed or adopted by a Party with current intention to authenticate this Amendment.

(b) Delivery of a copy of this Amendment bearing an original signature by facsimile

transmission (whether directly from one facsimile device to another by means of a dial-up connection or whether mediated by the worldwide web), by electronic mail in “portable document format” (“.pdf”) form, or by any other electronic means intended to preserve the original graphic and pictorial appearance of a document, or by combination of such means, shall have the same effect as physical delivery of the paper document bearing the original signature. “Originally signed” or “original signature” means or refers to a signature that has not been mechanically or electronically reproduced.

IN WITNESS WHEREOF, each party hereto has caused this Amendment to be duly executed by its authorized officer or representative as of the date first written above.

[Signature pages follow]

NRG McCLAIN LLC, a Delaware limited liability company

By: /s/ George P. Schaefer

Name: George P. Schaefer

Title: Treasurer

OKLAHOMA GAS AND ELECTRIC COMPANY, an Oklahoma corporation

By: /s/ Al M. Strecker

Name: Al M. Strecker

Title: Executive Vice President and Chief Operating Officer

Consented to in accordance with the provisions of the ORCA as of the date first written above.

WESTLB AG, NEW YORK BRANCH
As Agent

By: /s/ Jared Brenner

Name: Jared Brenner

Title: Director

By: /s/ Michael G. Pantelogianis

Name: Michael G. Pantelogianis

Title: Associate Director

Exhibit 2.04

AMENDMENT NO. 2 TO ASSET PURCHASE AGREEMENT

THIS AMENDMENT NO. 2 TO ASSET PURCHASE AGREEMENT (this "Amendment"), dated as of October 27, 2003, is made by **NRG McCLAIN LLC**, a Delaware limited liability company ("Seller"), and **OKLAHOMA GAS AND ELECTRIC COMPANY**, an Oklahoma corporation ("Buyer").

RECITALS

A. Seller and Buyer entered into a Asset Purchase Agreement, dated as of August 18,2003, as amended by that Amendment No. 1 to Asset Purchase Agreement dated as of October 22,2003 (as so amended, the "Agreement"; capitalized terms used but not defined in this Amendment have the meanings ascribed to such terms in the Agreement).

B. Seller is the debtor and debtor in possession in Case No. 03-15205(PCB) (the "Case") under Chapter 11 of the United States Bankruptcy Code currently pending in the United States Bankruptcy Court for the Southern District of New York (the "Bankruptcy Court"), which Case is being jointly administered with several other affiliated Chapter 11 cases under Case No. 03-13204(PCB).

C. Seller and Buyer wish to amend the Agreement to revise Item 2 of Schedule 3.15 to the Agreement.

NOW, THEREFORE, in consideration of the premises and for other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the parties hereto agree to amend the Agreement as follows:

ARTICLE I
Amendment to Agreement

SECTION 1.1 Amendment of Item 2 of Schedule 3.15. Item 2 of Schedule 3.15 to the Agreement is hereby amended and restated to read as follows:

"2. Seller submitted a claim to Duke/Fluor Daniel ("D/FD") for repair costs incurred by Seller resulting from D/FD's premature replacement of fine mesh filter screens with coarse mesh screens in the steam turbine during the Power Plant's initial operation period. This claim was substantially resolved in accordance with a letter agreement dated September 26, 2002, between D/FD and Seller. In addition, representatives of D/FD had agreed in principal with representatives of Seller for the payment by D/FD of $250,000 in consideration of the full and final release of D/FD from any additional exposure with respect to this claim, which contemplated the

performance by Seller, at Seller's expense, of a final Combined Reheat Valve Screen Inspection, including replacement of filter screens (the "CRVSI"). Seller has scheduled the CRVSI to occur commencing on or about November 10, 2003. Buyer and Seller agree that (a) Seller is hereby authorized to execute a settlement agreement with D/FD in the form approved by both Buyer and Seller, as evidenced by the execution thereof, or, in the case of Buyer, an addendum thereto; (b) Schedule 3.8 shall be amended to add such settlement agreement to such schedule; (c) if the Closing shall not have occurred on or prior to the scheduled date of commencement of the CRVSI, Seller shall perform or cause to be performed the CRVSI, and, if the Closing thereafter occurs, Buyer shall then reimburse Seller for all out of pocket costs incurred by Seller in performing (or causing to be performed) the CRVSI and other unscheduled outage items, up to an aggregate of $250,000, and (d) if the Closing shall occur on or prior to the scheduled date of commencement of the CRVSI, Seller shall not be required to perform, or expend monies on account of, the CRVSI."

ARTICLE II
Miscellaneous

SECTION 2.1 References to the Agreement. (a) Each reference in the Agreement to *"this Agreement," "hereunder," "herein"* or words of like import shall mean and be a reference to the Agreement as amended and affected hereby.

(b) Each reference in the other Transaction Documents to the Agreement shall mean and be a reference to the Agreement, as amended and affected hereby.

SECTION 2.2. Effectiveness. This Amendment shall become effective upon the satisfaction, or waiver in writing by Seller and Buyer, of the following conditions:

(a) Each of Seller and Buyer shall have executed this Amendment;

(b) WestLB AG, as Agent (the "Agent") for the Lenders parties to that Omnibus Restructuring and Consent Agreement dated as of August 18, 2003 (the "ORCA"), by and among Seller, the Agent, the Lenders and the affiliates of Seller parties thereto, shall have executed a copy of this Amendment for the limited purpose of evidencing its consent to this Amendment in accordance with the provisions of the ORCA.

(c) An order of the Court approving this Amendment shall have been entered, if required under applicable bankruptcy law.

SECTION 2.3 Ratification. Each of Buyer and Seller acknowledges and ratifies the Agreement and the other Transaction Documents, as amended and affected hereby, and agrees and acknowledges that all the terms thereof as amended and affected hereby,

(a) are hereby brought forward for the benefit of the parties thereto, and (b) shall remain in full force and effect.

SECTION 2.4 Governing Law. This Amendment shall be governed by and construed in accordance with the laws of the State of New York without giving effect to any choice or conflict of law provision or rule (whether of the State of New York or any other jurisdiction) that would cause the application of the laws of any jurisdiction other than the State of New York, except to the extent preempted by federal bankruptcy laws.

SECTION 2.5 Headings and Definitions. The Section and Article headings contained in this Amendment are inserted for convenience of reference only and shall not affect the meaning or interpretation of this Amendment. All references to Sections or Articles contained herein mean Sections or Articles of this Amendment unless otherwise stated. All defined terms and phrases herein are equally applicable to both the singular and plural forms of such terms.

SECTION 2.6 Counterparts. This Amendment may be executed in one or more counterparts, all of which shall be considered one and the same agreement, and shall become effective when one or more counterparts have been signed by each of the parties and delivered to the other parties.

SECTION 2.7 Electronic Signatures.

(a) Notwithstanding the Electronic Signatures in Global and National Commerce Act (15 U.S.C. Sec. 7001 *et seq*.), the Uniform Electronic Transactions Act, or any other Law relating to or enabling the creation, execution, delivery, or recordation of any contract or signature by electronic means, and notwithstanding any course of conduct engaged in by the Parties, no Party shall be deemed to have executed this Amendment unless and until such Party shall have executed this Amendment on paper by a handwritten original signature or any other symbol executed or adopted by a Party with current intention to authenticate this Amendment.

(b) Delivery of a copy of this Amendment bearing an original signature by facsimile transmission (whether directly from one facsimile device to another by means of a dial-up connection or whether mediated by the worldwide web), by electronic mail in "portable document format" (".pdf") form, or by any other electronic means intended to preserve the original graphic and pictorial appearance of a document, or by combination of such means, shall have the same effect as physical delivery of the paper document bearing the original signature. "Originally signed" or "original signature" means or refers to a signature that has not been mechanically or electronically reproduced.

IN WITNESS WHEREOF, each party hereto has caused this Amendment to be duly executed by its authorized officer or representative as of the date first written above.

[Signature pages follow]

NRG McCLAIN LLC, a Delaware limited liability company

By: /s/ George P. Schaefer

Name: George P. Schaefer

Title: Treasurer

OKLAHOMA GAS AND ELECTRIC COMPANY, an Oklahoma corporation

By: /s/ Al M. Strecker

Name: Al M. Strecker

Title: Executive Vice President and Chief Operating Officer

Consented to in accordance with the provisions of the ORCA as of the date first written above.

WESTLB AG, NEW YORK BRANCH

As Agent

By: /s/ Jared Brenner

Name: Jared Brenner

Title: Director

By: /s/ Michael G. Pantelogianis

Name: Michael G. Pantelogianis

Title: Associate Director

Exhibit 2.05

AMENDMENT NO. 3 TO ASSET PURCHASE AGREEMENT

THIS AMENDMENT NO. 3 TO ASSET PURCHASE AGREEMENT (this "Amendment"), dated as of November 25, 2003, is made by **NRG McCLAIN LLC,** a Delaware limited liability company ("Seller"), and **OKLAHOMA GAS AND ELECTRIC COMPANY,** an Oklahoma corporation ("Buyer").

RECITALS

A. Seller and Buyer entered into a Asset Purchase Agreement, dated as of August 18, 2003, as amended by Amendment No. 1 and Amendment No. 2 thereto (as so amended, the "Agreement"; capitalized terms used but not defined in this Amendment have the meanings ascribed to such terms in the Agreement).

B. Seller is the debtor and debtor in possession in Case No. 03-15205(PCB) (the "Case") under Chapter 11 of the United States Bankruptcy Code currently pending in the United States Bankruptcy Court for the Southern District of New York (the "Bankruptcy Court"), which Case is being jointly administered with several other affiliated Chapter 11 cases under Case No. 03-13204(PCB).

C. Seller and Buyer wish to amend the Agreement to revise the optional termination date provided for in the Agreement.

NOW, THEREFORE, in consideration of the premises and for other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the parties hereto agree to amend the Agreement as follows:

ARTICLE I
Amendment to Agreement

SECTION 1.1 Amendment of Section 12.1. Clauses (b) and (c) of Section 12.1 of the Agreement are hereby amended and restated to read as follows:

(b) Buyer, if the Closing has not occurred on or before January 31, 2004 and the failure to consummate the Asset Purchase on or before such date did not result from the failure by Buyer to fulfill any undertaking or commitment provided for herein that is required to be fulfilled prior to the Closing;

(c) Seller, if the Closing has not occurred on or before January 31, 2004 and the failure to consummate the Asset Purchase on or before such date did not result from the failure by Seller to fulfill any undertaking or commitment provided for herein that is required to be fulfilled prior to the Closing;

ARTICLE II
Miscellaneous

SECTION 2.1 References to the Agreement. (a) Each reference in the Agreement to *"this Agreement," "hereunder," "herein"* or words of like import shall mean and be a reference to the Agreement as amended and affected hereby.

(b) Each reference in the other Transaction Documents to the Agreement shall mean and be a reference to the Agreement, as amended and affected hereby.

SECTION 2.2. Effectiveness. This Amendment shall become effective upon the satisfaction, or waiver in writing by Seller and Buyer, of the following conditions:

(a) Each of Seller and Buyer shall have executed this Amendment; and

(b) WestLB AG, as Agent (the "Agent") for the Lenders parties to that Omnibus Restructuring and Consent Agreement dated as of August 18, 2003 (the "ORCA"), by and among Seller, the Agent, the Lenders and the affiliates of Seller parties thereto, shall have executed a copy of this Amendment for the limited purpose of evidencing its consent to this Amendment in accordance with the provisions of the ORCA.

SECTION 2.3 Ratification. Each of Buyer and Seller acknowledges and ratifies the Agreement and the other Transaction Documents, as amended and affected hereby, and agrees and acknowledges that all the terms thereof as amended and affected hereby, (a) are hereby brought forward for the benefit of the parties thereto, and (b) shall remain in full force and effect.

SECTION 2.4 Governing Law. This Amendment shall be governed by and construed in accordance with the laws of the State of New York without giving effect to any choice or conflict of law provision or rule (whether of the State of New York or any other jurisdiction) that would cause the application of the laws of any jurisdiction other than the State of New York, except to the extent preempted by federal bankruptcy laws.

SECTION 2.5 Headings and Definitions. The Section and Article headings contained in this Amendment are inserted for convenience of reference only and shall not affect the meaning or interpretation of this Amendment. All references to Sections or Articles contained herein mean Sections or Articles of this Amendment unless otherwise stated. All defined terms and phrases herein are equally applicable to both the singular and plural forms of such terms.

SECTION 2.6 Counterparts. This Amendment may be executed in one or more counterparts, all of which shall be considered one and the same agreement, and shall become effective when one or more counterparts have been signed by each of the parties and delivered to the other parties.

SECTION 2.7 Electronic Signatures.

(a) Notwithstanding the Electronic Signatures in Global and National Commerce Act

(15 U.S.C. Sec. 7001 *et seq.*), the Uniform Electronic Transactions Act, or any other Law relating to or enabling the creation, execution, delivery, or recordation of any contract or signature by electronic means, and notwithstanding any course of conduct engaged in by the Parties, no Party shall be deemed to have executed this Amendment unless and until such Party shall have executed this Amendment on paper by a handwritten original signature or any other symbol executed or adopted by a Party with current intention to authenticate this Amendment.

(b) Delivery of a copy of this Amendment bearing an original signature by facsimile transmission (whether directly from one facsimile device to another by means of a dial-up connection or whether mediated by the worldwide web), by electronic mail in “portable document format” (“.pdf”) form, or by any other electronic means intended to preserve the original graphic and pictorial appearance of a document, or by combination of such means, shall have the same effect as physical delivery of the paper document bearing the original signature. “Originally signed” or “original signature” means or refers to a signature that has not been mechanically or electronically reproduced.

IN WITNESS WHEREOF, each party hereto has caused this Amendment to be duly executed by its authorized officer or representative as of the date first written above.

[Signature pages follow]

NRG McCLAIN LLC, a Delaware limited liability company

By: /s/ George P. Schaefer

Name: George P. Schaefer

Title: Treasurer

OKLAHOMA GAS AND ELECTRIC COMPANY, an Oklahoma corporation

By: /s/ James R. Hatfield

Name: James R. Hatfield

Title: Senior Vice President and Chief Financial Officer

Consented to in accordance with the provisions of the ORCA as of the date first written above.

WESTLB AG, NEW YORK BRANCH
As Agent

By: /s/ Michael G. Pantelogianis

Name: Michael G. Pantelogianis

Title: Associate Director

By: /s/ Remy Savoya

Name: Remy Savoya

Title: Analyst

Exhibit 2.06

AMENDMENT NO. 4 TO ASSET PURCHASE AGREEMENT

THIS AMENDMENT NO. 4 TO ASSET PURCHASE AGREEMENT (this "Amendment"), dated as of January 28, 2004, is made by **NRG McCLAIN LLC,** a Delaware limited liability company ("Seller"), and **OKLAHOMA GAS AND ELECTRIC COMPANY,** an Oklahoma corporation ("Buyer").

RECITALS

A. Seller and Buyer entered into a Asset Purchase Agreement, dated as of August 18, 2003, as amended by Amendments No. 1, 2 and 3 thereto (as so amended, the "Agreement"; capitalized terms used but not defined in this Amendment have the meanings ascribed to such terms in the Agreement).

B. Seller is the debtor and debtor in possession in Case No. 03-15205(PCB) (the "Case") under Chapter 11 of the United States Bankruptcy Code currently pending in the United States Bankruptcy Court for the Southern District of New York (the "Bankruptcy Court"), which Case is being jointly administered with several other affiliated Chapter 11 cases under Case No. 03-13204(PCB).

C. Seller and Buyer wish to amend the Agreement to revise (i) the optional termination date provided for in the Agreement and (ii) Item 2 of Schedule 3.15 to the Agreement.

NOW, THEREFORE, in consideration of the premises and for other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the parties hereto agree to amend the Agreement as follows:

ARTICLE I
Amendment to Agreement

SECTION 1.1 Amendment of Section 12.1. Clauses (b) and (c) of Section 12.1 of the Agreement are hereby amended and restated to read as follows:

"(b) Buyer, if the Closing has not occurred on or before February 14, 2004 and the failure to consummate the Asset Purchase on or before such date did not result from the failure by Buyer to fulfill any undertaking or commitment provided for herein that is required to be fulfilled prior to the Closing;

(c) Seller, if the Closing has not occurred on or before February 14, 2004 and the failure to consummate the Asset Purchase on or before such date did not result from the failure by Seller to fulfill any undertaking or commitment provided for herein that is required to be fulfilled prior to the Closing;"

SECTION 1.2 Amendment of Item 2 of Schedule 3.15. Item 2 of Schedule 3.15 to the

Agreement is hereby amended and restated to read as follows:

"2. Seller submitted a claim to Duke/Fluor Daniel ("D/FD") for repair costs incurred by Seller resulting from D/FD's premature replacement of fine mesh filter screens with coarse mesh screens in the steam turbine during the Power Plant's initial operation period. This claim was substantially resolved in accordance with a letter agreement dated September 26, 2002, between D/FD and Seller. In addition, representatives of D/FD had agreed in principle with representatives of Seller for the payment by D/FD of $250,000 in consideration of the full and final release of D/FD from any additional exposure with respect to this claim, which contemplated the performance by Seller, at Seller's expense, of a final Combined Reheat Valve Screen Inspection, including replacement of filter screens (the "CRVSI"). Seller has scheduled the CRVSI to occur commencing on or about November 10, 2003. Buyer and Seller agree that (a) Seller is hereby authorized to execute a settlement agreement with D/FD (and any amendments thereto) in the form(s) approved by both Buyer and Seller, as evidenced by the execution by Buyer and Seller thereof, or, in the case of Buyer, an addendum thereto; (b) Schedule 3.8 shall be amended to add such settlement agreement (and any such approved amendments) to such schedule; and (c) if the Closing shall not have occurred on or prior to the scheduled date of commencement of the CRVSI, Seller shall perform or cause to be performed the CRVSI."

ARTICLE II
Miscellaneous

SECTION 2.1 References to the Agreement. (a) Each reference in the Agreement to *"this Agreement," "hereunder," "herein"* or words of like import shall mean and be a reference to the Agreement as amended and affected hereby.

(b) Each reference in the other Transaction Documents to the Agreement shall mean and be a reference to the Agreement, as amended and affected hereby.

SECTION 2.2. Effectiveness. This Amendment shall become effective upon the satisfaction, or waiver in writing by Seller and Buyer, of the following conditions:

(a) Each of Seller and Buyer shall have executed this Amendment; and

(b) WestLB AG, as Agent (the "Agent") for the Lenders parties to that Omnibus Restructuring and Consent Agreement dated as of August 18, 2003 (the "ORCA"), by and among Seller, the Agent, the Lenders and the affiliates of Seller parties thereto, shall have executed a copy of this Amendment for the limited purpose of evidencing its consent to this Amendment in accordance with the provisions of the ORCA.

SECTION 2.3 Ratification. Each of Buyer and Seller acknowledges and ratifies the Agreement and the other Transaction Documents, as amended and affected hereby, and agrees and acknowledges that all the terms thereof as amended and affected hereby, (a) are hereby brought forward for the benefit of the parties thereto, and (b) shall remain in full force and effect.

SECTION 2.4 Governing Law. This Amendment shall be governed by and construed in

accordance with the laws of the State of New York without giving effect to any choice or conflict of law provision or rule (whether of the State of New York or any other jurisdiction) that would cause the application of the laws of any jurisdiction other than the State of New York, except to the extent preempted by federal bankruptcy laws.

SECTION 2.5 Headings and Definitions. The Section and Article headings contained in this Amendment are inserted for convenience of reference only and shall not affect the meaning or interpretation of this Amendment. All references to Sections or Articles contained herein mean Sections or Articles of this Amendment unless otherwise stated. All defined terms and phrases herein are equally applicable to both the singular and plural forms of such terms.

SECTION 2.6 Counterparts. This Amendment may be executed in one or more counterparts, all of which shall be considered one and the same agreement, and shall become effective when one or more counterparts have been signed by each of the parties and delivered to the other parties.

SECTION 2.7 Electronic Signatures.

(a) Notwithstanding the Electronic Signatures in Global and National Commerce Act (15 U.S.C. Sec. 7001 *et seq*.), the Uniform Electronic Transactions Act, or any other Law relating to or enabling the creation, execution, delivery, or recordation of any contract or signature by electronic means, and notwithstanding any course of conduct engaged in by the Parties, no Party shall be deemed to have executed this Amendment unless and until such Party shall have executed this Amendment on paper by a handwritten original signature or any other symbol executed or adopted by a Party with current intention to authenticate this Amendment.

(b) Delivery of a copy of this Amendment bearing an original signature by facsimile transmission (whether directly from one facsimile device to another by means of a dial-up connection or whether mediated by the worldwide web), by electronic mail in “portable document format” (“.pdf”) form, or by any other electronic means intended to preserve the original graphic and pictorial appearance of a document, or by combination of such means, shall have the same effect as physical delivery of the paper document bearing the original signature. “Originally signed” or “original signature” means or refers to a signature that has not been mechanically or electronically reproduced.

SECTION 2.8 Duke/Fluor Daniel Settlement Payment. Buyer agrees that if, pursuant to Section 1 of the Settlement Agreement, dated as of October, 28, 2003, between Duke/Fluor Daniel and Seller (the “Settlement Agreement”), Duke/Fluor Daniel pays the Settlement Payment (as defined in the Settlement Agreement) to Buyer, Buyer shall promptly pay such amount over to Seller.

IN WITNESS WHEREOF, each party hereto has caused this Amendment to be duly executed by its authorized officer or representative as of the date first written above.

[Signature pages follow]

NRG McCLAIN LLC, a Delaware limited liability company

By: /s/ George P. Schaefer
Name: George P. Schaefer
Title: Treasurer

OKLAHOMA GAS AND ELECTRIC COMPANY, an Oklahoma corporation

By: /s/ James R. Hatfield
Name: James R. Hatfield
Title: Senior Vice President and Chief Financial Officer

Consented to in accordance with the provisions of the ORCA as of the date first written above.

WESTLB AG, NEW YORK BRANCH
As Agent

By: /s/ Michael G. Pantelogianis
Name: Michael G. Pantelogianis
Title: Associate Director

By: /s/ Remy Savoya
Name: Remy Savoya

Title: Analyst

Exhibit 2.07

AMENDMENT NO. 5 TO ASSET PURCHASE AGREEMENT

THIS AMENDMENT NO. 5 TO ASSET PURCHASE AGREEMENT (this "Amendment"), dated as of February 13, 2004, is made by **NRG McCLAIN LLC,** a Delaware limited liability company ("Seller"), and **OKLAHOMA GAS AND ELECTRIC COMPANY,** an Oklahoma corporation ("Buyer").

RECITALS

A. Seller and Buyer entered into a Asset Purchase Agreement, dated as of August 18, 2003, as amended by Amendments No. 1, 2, 3 and 4 thereto (as so amended, the "Agreement"; capitalized terms used but not defined in this Amendment have the meanings ascribed to such terms in the Agreement).

B. Seller is the debtor and debtor in possession in Case No. 03-15205(PCB) (the "Case") under Chapter 11 of the United States Bankruptcy Code currently pending in the United States Bankruptcy Court for the Southern District of New York (the "Bankruptcy Court"), which Case is being jointly administered with several other affiliated Chapter 11 cases under Case No. 03-13204(PCB).

C. Seller and Buyer wish to amend the Agreement to revise the optional termination date provided for in the Agreement.

NOW, THEREFORE, in consideration of the premises and for other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the parties hereto agree to amend the Agreement as follows:

ARTICLE I
Amendment to Agreement

SECTION 1.1 Amendment of Section 12.1.

(a) Clauses (b) and (c) of Section 12.1 of the Agreement are hereby amended and restated to read as follows:

"(b) Buyer, if the Closing has not occurred on or before March 1, 2004 and the failure to consummate the Asset Purchase on or before such date did not result from the failure by Buyer to fulfill any undertaking or commitment provided for herein that is required to be fulfilled prior to the Closing;

(c) Seller, if the Closing has not occurred on or before March 1, 2004 and the failure to consummate the Asset Purchase on or before such date did not result from the failure by Seller to fulfill any undertaking or commitment provided for herein that is required to be fulfilled prior to the Closing;".

(b) Upon separate written consent thereto by the agent for the Prepetition Lenders, in its capacity as such, clauses (b) and (c) of Section 12.1 of the Agreement shall as of the date of such consent be further amended and restated to read as follows:

"(b) Buyer, if the Closing has not occurred on or before March 16, 2004 and the failure to consummate the Asset Purchase on or before such date did not result from the failure by Buyer to fulfill any undertaking or commitment provided for herein that is required to be fulfilled prior to the Closing;

(c) Seller, if the Closing has not occurred on or before March 16, 2004 and the failure to consummate the Asset Purchase on or before such date did not result from the failure by Seller to fulfill any undertaking or commitment provided for herein that is required to be fulfilled prior to the Closing;".

ARTICLE II
Miscellaneous

SECTION 2.1 References to the Agreement. (a) Each reference in the Agreement to *"this Agreement," "hereunder," "herein"* or words of like import shall mean and be a reference to the Agreement as amended and affected hereby.

(b) Each reference in the other Transaction Documents to the Agreement shall mean and be a reference to the Agreement, as amended and affected hereby.

SECTION 2.2. Effectiveness. This Amendment shall become effective upon the satisfaction, or waiver in writing by Seller and Buyer, of the following conditions:

(a) Each of Seller and Buyer shall have executed this Amendment; and

(b) WestLB AG, as Agent (the "Agent") for the Lenders parties to that Omnibus Restructuring and Consent Agreement dated as of August 18, 2003 (the "ORCA"), by and among Seller, the Agent, the Lenders and the affiliates of Seller parties thereto, shall have executed a copy of this Amendment for the limited purpose of evidencing its consent to this Amendment in accordance with the provisions of the ORCA.

SECTION 2.3 Ratification. Each of Buyer and Seller acknowledges and ratifies the Agreement and the other Transaction Documents, as amended and affected hereby, and agrees and acknowledges that all the terms thereof as amended and affected hereby, (a) are hereby brought forward for the benefit of the parties thereto, and (b) shall remain in full force and effect.

SECTION 2.4 Governing Law. This Amendment shall be governed by and construed in accordance with the laws of the State of New York without giving effect to any choice or conflict of law provision or rule (whether of the State of New York or any other jurisdiction) that would cause the application of the laws of any jurisdiction other than the State of New York, except to the extent preempted by federal bankruptcy laws.

SECTION 2.5 Headings and Definitions. The Section and Article headings contained in

this Amendment are inserted for convenience of reference only and shall not affect the meaning or interpretation of this Amendment. All references to Sections or Articles contained herein mean Sections or Articles of this Amendment unless otherwise stated. All defined terms and phrases herein are equally applicable to both the singular and plural forms of such terms.

SECTION 2.6 Counterparts. This Amendment may be executed in one or more counterparts, all of which shall be considered one and the same agreement, and shall become effective when one or more counterparts have been signed by each of the parties and delivered to the other parties.

SECTION 2.7 Electronic Signatures.

(a) Notwithstanding the Electronic Signatures in Global and National Commerce Act (15 U.S.C. Sec. 7001 *et seq*.), the Uniform Electronic Transactions Act, or any other Law relating to or enabling the creation, execution, delivery, or recordation of any contract or signature by electronic means, and notwithstanding any course of conduct engaged in by the Parties, no Party shall be deemed to have executed this Amendment unless and until such Party shall have executed this Amendment on paper by a handwritten original signature or any other symbol executed or adopted by a Party with current intention to authenticate this Amendment.

(b) Delivery of a copy of this Amendment bearing an original signature by facsimile transmission (whether directly from one facsimile device to another by means of a dial-up connection or whether mediated by the worldwide web), by electronic mail in “portable document format” (“.pdf”) form, or by any other electronic means intended to preserve the original graphic and pictorial appearance of a document, or by combination of such means, shall have the same effect as physical delivery of the paper document bearing the original signature. “Originally signed” or “original signature” means or refers to a signature that has not been mechanically or electronically reproduced.

IN WITNESS WHEREOF, each party hereto has caused this Amendment to be duly executed by its authorized officer or representative as of the date first written above.

[Signature pages follow]

NRG McCLAIN LLC, a Delaware limited liability company

By: /s/ George P. Schaefer
Name: George P. Schaefer
Title: Treasurer

OKLAHOMA GAS AND ELECTRIC COMPANY, an Oklahoma corporation

By: /s/ James R. Hatfield
Name: James R. Hatfield
Title: Senior Vice President and Chief Financial Officer

Consented to in accordance with the provisions of the ORCA as of the date first written above.

WESTLB AG, NEW YORK BRANCH
As Agent

By: /s/ George Suspanic
Name: George Suspanic
Title: Managing Director

By: /s/ Michael G. Pantelogianis
Name: Michael G. Pantelogianis
Title: Associate Director

Exhibit 10.22

CREDIT AGREEMENT

DATED AS OF DECEMBER 11, 2003

AMONG

OGE ENERGY CORP.,

THE LENDERS

AND

BANK ONE, NA
AS ADMINISTRATIVE AGENT

AND

WACHOVIA BANK, NATIONAL ASSOCIATION
AS SYNDICATION AGENT

AND

COMMERZBANK AG, CITIBANK, N.A. AND THE BANK OF NEW YORK
AS CO-DOCUMENTATION AGENTS

BANC ONE CAPITAL MARKETS, INC. AND WACHOVIA CAPITAL MARKETS LLC,
AS CO-LEAD ARRANGERS AND JOINT BOOK RUNNERS

SIDLEY AUSTIN BROWN & WOOD LLP
Bank One Plaza
10 South Dearborn Street
Chicago, Illinois 60603

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CREDIT AGREEMENT

This Agreement, dated as of December 11, 2003, is among OGE Energy Corp., an Oklahoma corporation, the Lenders and Bank One, NA, a national banking association having its principal office in Chicago, Illinois, as Administrative Agent and Wachovia Bank, National Association, as Syndication Agent, Commerzbank, AG, Citibank, N.A. and The Bank of New York as Co-Documentation Agents. The parties hereto agree as follows:

ARTICLE I

DEFINITIONS

As used in this Agreement:

"Accounting Changes" is defined in Section 9.8 hereof.

"Advance" means a borrowing hereunder, (i) made by the Lenders on the same Borrowing Date, or (ii) converted or continued by the Lenders on the same date of conversion or continuation, consisting, in either case, of the aggregate amount of the several Loans of the same Type and, in the case of Eurodollar Loans, for the same Interest Period.

"Affiliate" of any Person means any other Person directly or indirectly controlling, controlled by or under common control with such Person. A Person shall be deemed to control another Person if the controlling Person owns 10% or more of any class of voting securities (or other ownership interests) of the controlled Person or possesses, directly or indirectly, the power to direct or cause the direction of the management or policies of the controlled Person, whether through ownership of stock, by contract or otherwise.

"Agent" means Bank One in its capacity as contractual representative of the Lenders pursuant to Article X, and not in its individual capacity as a Lender, as Administrative Agent, and any successor Agent appointed pursuant to Article X.

"Aggregate Commitment" means the aggregate of the Commitments of all the Lenders, as reduced from time to time pursuant to the terms hereof. The initial Aggregate Commitment is Three Hundred Million and 00/100 Dollars ($300,000,000).

"Aggregate Outstanding Credit Exposure" means, at any time, the aggregate of the Outstanding Credit Exposure of all the Lenders.

"Agreement" means this Credit Agreement, as it may be amended, restated, supplemented or otherwise modified and as in effect from time to time.

"Agreement Accounting Principles" means generally accepted accounting principles applied in a manner consistent with that used in preparing the financial statements referred to in Section 5.4, as modified in accordance with Section 9.8.

"Alternate Base Rate" means, for any day, a fluctuating rate of interest per annum equal to the higher of (i) the Prime Rate for such day and (ii) the sum of the Federal Funds Effective Rate for such day and one half of one percent (0.5%) per annum.

"Applicable Fee Rate" means, with respect to the Facility Fee and the Utilization Fee at any time, the percentage rate per annum which is applicable at such time with respect to each such fee as set forth in the Pricing Schedule.

"Applicable Margin" means, with respect to Advances of any Type at any time, the percentage rate per annum which is applicable at such time with respect to Advances of such Type as set forth in the Pricing Schedule.

"Approved Fund" means any Fund that is administered or managed by (a) a Lender, (b) an Affiliate of a Lender or (c) an entity or an Affiliate of an entity that administers or manages a Lender.

"Arranger" means each of (i) Banc One Capital Markets, Inc., a Delaware corporation and (ii) Wachovia Capital Markets LLC, a Delaware limited liability company, and their respective successors, in its capacity as Co-Lead Arranger and Joint Book Runner.

"Article" means an article of this Agreement unless another document is specifically referenced.

"Authorized Officer" means any of the President, Chief Financial Officer, Treasurer, or any Vice President of the Borrower, acting singly.

"Bank One" means Bank One, NA, a national banking association having its principal office in Chicago, Illinois, in its individual capacity, and its successors.

"Borrower" means OGE Energy Corp., an Oklahoma corporation, and its permitted successors and assigns (including, without limitation, a debtor in possession on its behalf).

"Borrowing Date" means a date on which an Advance is made hereunder.

"Borrowing Notice" is defined in Section 2.8.

"Business Day" means (i) with respect to any borrowing, payment or rate selection of Eurodollar Advances, a day (other than a Saturday or Sunday) on which banks generally are open in Chicago, Illinois and New York, New York for the conduct of substantially all of their commercial lending activities, interbank wire transfers can be made on the Fedwire system and dealings in United States dollars are carried on in the London interbank market and (ii) for all other purposes, a day (other than a Saturday or Sunday) on which banks generally are open in Chicago, Illinois for the conduct of substantially all of their commercial lending activities and interbank wire transfers can be made on the Fedwire system.

"Capitalized Lease" of a Person means any lease of Property by such Person as lessee which would be capitalized on a balance sheet of such Person prepared in accordance with Agreement Accounting Principles.

"Capitalized Lease Obligations" of a Person means the amount of the obligations of such Person under Capitalized Leases which would be shown as a liability on a balance sheet of such Person prepared in accordance with Agreement Accounting Principles.

"Change in Control" means (i) the acquisition by any Person, or two or more Persons acting in concert, of beneficial ownership (within the meaning of Rule 13d-3 of the Securities and Exchange Commission under the Securities Exchange Act of 1934) of 30% or more of the outstanding shares of voting stock of the Borrower or (ii) the majority of the Board of Directors of the Borrower fails to consist of Continuing Directors.

"Closing Date" means December 11, 2003.

"Code" means the Internal Revenue Code of 1986, as amended, reformed or otherwise modified from time to time, and any rule or regulation issued thereunder.

"Co-Documentation Agent" means each of Commerzbank, AG, Citibank, N.A. and The Bank of New York, in its capacity as Co-Documentation Agent hereunder.

"Commitment" means, for each Lender, the amount set forth on the Commitment Schedule opposite such Lender's name, as it may be modified as a result of any assignment that has become effective pursuant to Section 12.3 or as otherwise modified from time to time pursuant to the terms hereof.

"Commitment Schedule" means the Schedule identifying each Lender's Commitment as of the Closing Date attached hereto and identified as such.

"Consolidated Capitalization" means the sum of (a) all of the shareholders' equity or net worth of the Borrower and its Subsidiaries on a consolidated basis, as determined in accordance with Agreement Accounting Principles plus (b) Consolidated Indebtedness plus (c) 50% of the principal amount of the 8.375% Trust Preferred Securities maturing 2039 as long as (i) they are fully subordinated to all current and future debt obligations of the Borrower and its Subsidiaries and (ii) no amortization, redemption or defeasance is required or occurs with respect to such Indebtedness prior to the maturity of such Indebtedness.

"Consolidated EBITDA" means, for any period, without duplication, an amount equal to (a) Consolidated Net Income (excluding any extraordinary gains or any losses) for such period plus (b) an amount which in the determination of Consolidated Net Income for such period was deducted for (i) Consolidated Interest Expense, (ii) income tax expense, (iii) depreciation expense and (iv) amortization expense plus (c) non-cash items reducing Consolidated Net Income for such period less (d) non-cash items increasing Consolidated Net Income for such period.

"Consolidated Indebtedness" means, as of any date of determination, with respect to the Borrower and its Subsidiaries on a consolidated basis, an amount equal to all Indebtedness of the Borrower and its Subsidiaries as of such date; provided that it is understood and agreed that (a) Indebtedness of NOARK Pipeline Finance, L.L.C. that is not guaranteed by Enogex, Inc. (even if such Indebtedness is consolidated for accounting purposes) shall not be considered to be Consolidated Indebtedness, (b) Indebtedness in connection with the off-balance sheet leasing of

rail cars by a regulated subsidiary of the Borrower shall not be considered to be Consolidated Indebtedness if the payments in connection therewith are included in the rate base as approved by the applicable governing commissions and are collected from customers who are obligated to make such payments, (c) 50% of the principal amount of the 8.375% Trust Preferred Securities maturing 2039 shall not be considered to be Consolidated Indebtedness as long as (A) they are fully subordinated to all current and future debt obligations of the Borrower and its Subsidiaries and (B) no amortization, redemption or defeasance is required or occurs with respect to such Indebtedness prior to the maturity of such Indebtedness and (d) Indebtedness of any special purpose Subsidiary in connection with Receivables Purchase Facilities which Indebtedness is not reflected on the consolidated balance of the Borrower and does not exceed, in the aggregate at any one time, $15,200,000, shall not be considered to be Consolidated Indebtedness.

"Consolidated Interest Expense" means, for any period, with respect to the Borrower and its Subsidiaries on a consolidated basis, an amount equal to total interest expense of the Borrower and its Subsidiaries for such period (including, without limitation, all such interest expense accrued or capitalized during such period, whether or not actually paid during such period), as determined in accordance with Agreement Accounting Principles.

"Consolidated Net Income" means, with reference to any period, the net income (or loss) of the Borrower and its Subsidiaries calculated on a consolidated basis for such period in accordance with Agreement Accounting Principles.

"Contingent Obligation" of a Person means any agreement, undertaking or arrangement by which such Person assumes, guarantees, contingently agrees to purchase or provide funds for the payment of, or otherwise becomes or is contingently liable upon, the obligation or liability of any other Person, or agrees to maintain the net worth or working capital or other financial condition of any other Person, or otherwise assures any creditor of such other Person against loss, including, without limitation, any comfort letter, operating agreement, take-or-pay contract or the obligations of any such Person as general partner of a partnership with respect to the liabilities of the partnership.

"Continuing Director" means, with respect to any Person as of any date of determination, any member of the board of directors of such Person who (a) was a member of such board of directors on the Closing Date, or (b) was nominated for election or elected to such board of directors with the approval of a majority of the Continuing Directors who were members of such board at the time of such nomination or election.

"Controlled Group" means all members of a controlled group of corporations or other business entities and all trades or businesses (whether or not incorporated) under common control which, together with the Borrower or any of its Subsidiaries, are treated as a single employer under Section 414 of the Code.

"Conversion/Continuation Notice" is defined in Section 2.9.

"Default" means an event described in Article VII.

"Designated Lender" means, with respect to each Designating Lender, each Eligible Designee designated by such Designating Lender pursuant to Section 12.1.2.

"Designating Lender" means, with respect to each Designated Lender, the Lender that designated such Designated Lender pursuant to Section 12.1.2.

"Designation Agreement" is defined in Section 12.1.2.

"Dollar" and "$" means dollars in the lawful currency of the United States of America.

"Eligible Designee**"** means a special purpose corporation, partnership, limited partnership or limited liability company that is administered by the respective Designating Lender or an Affiliate of such Designating Lender and (i) is organized under the laws of the United States of America or any state thereof, (ii) is engaged primarily in making, purchasing or otherwise investing in commercial loans in the ordinary course of its business and (iii) issues (or the parent of which issues) commercial paper rated at least A-1 or the equivalent thereof by S&P or the equivalent thereof by Moody's.

"Environmental Laws" means any and all federal, state, local and foreign statutes, laws, judicial decisions, regulations, ordinances, rules, judgments, orders, decrees, plans, injunctions, permits, concessions, grants, franchises, licenses, agreements and other governmental restrictions relating to (i) the protection of the environment, (ii) the effect of the environment on human health, (iii) emissions, discharges or releases of pollutants, contaminants, hazardous substances or wastes into surface water, ground water or land, or (iv) the manufacture, processing, distribution, use, treatment, storage, disposal, transport or handling of pollutants, contaminants, hazardous substances or wastes or the clean-up or other remediation thereof.

"ERISA" means the Employee Retirement Income Security Act of 1974, as amended from time to time, and any rules or regulations issued thereunder.

"Eurodollar Advance" means an Advance which, except as otherwise provided in Section 2.11, bears interest at the applicable Eurodollar Rate.

"Eurodollar Base Rate" means, with respect to a Eurodollar Advance for the relevant Interest Period, the applicable British Bankers' Association Interest Settlement Rate for deposits in Dollars appearing on Reuters Screen FRBD as of 11:00 a.m. (London time) two (2) Business Days prior to the first day of such Interest Period, and having a maturity equal to such Interest Period, *provided* that, (i) if Reuters Screen FRBD is not available to the Agent for any reason, the applicable Eurodollar Base Rate for the relevant Interest Period shall instead be the applicable British Bankers' Association Interest Settlement Rate for deposits in Dollars as reported by any other generally recognized financial information service as of 11:00 a.m. (London time) two (2) Business Days prior to the first day of such Interest Period, and having a maturity equal to such Interest Period, and (ii) if no such British Bankers' Association Interest Settlement Rate is available to the Agent, the applicable Eurodollar Base Rate for the relevant Interest Period shall instead be the rate determined by the Agent to be the rate at which Bank One or one of its affiliate banks offers to place deposits in Dollars with first class banks in the London interbank market at approximately 11:00 a.m. (London time) two (2) Business Days prior to the first day of such Interest Period, in the approximate amount of Bank One's relevant Eurodollar Loan, and having a maturity equal to such Interest Period.

"Eurodollar Loan" means a Loan which, except as otherwise provided in Section 2.11, bears interest at the applicable Eurodollar Rate.

"Eurodollar Rate" means, with respect to a Eurodollar Advance for the relevant Interest Period, the sum of (i) the quotient of (a) the Eurodollar Base Rate applicable to such Interest Period, divided by (b) one minus the Reserve Requirement (expressed as a decimal) applicable to such Interest Period, plus (ii) the Applicable Margin, plus (iii) from and after the Loan Conversion Date, the Term Loan Margin.

"Excluded Taxes" means, in the case of each Lender or applicable Lending Installation and the Agent, taxes imposed on its overall net income, and franchise taxes (imposed in lieu of net income taxes) imposed on it, by (i) the jurisdiction under the laws of which such Lender or the Agent is incorporated or organized or any political combination or subdivision or taxing authority thereof or (ii) the jurisdiction in which the Agent's or such Lender's principal executive office or such Lender's applicable Lending Installation is located.

"Exhibit" refers to an exhibit to this Agreement, unless another document is specifically referenced.

"Existing Credit Agreement" means (i) that certain Credit Agreement dated as of January 8, 2003 among the Borrower, the financial institutions party thereto as lenders and agents and Bank of America, N.A., as administrative agent and (ii) that certain Credit Agreement dated as of January 15, 1999 among the Borrower, the financial institutions party thereto and Bank One, NA (as successor to the First National Bank of Chicago), as administrative agent, as each of the same has been amended, restated, supplemented or otherwise modified from time to time.

"Facility Fee" is defined in Section 2.5.1.

"Facility Termination Date" means the Revolving Credit Termination Date, provided that if the Borrower has given notice to the Agent pursuant to Section 2.1 to convert the Loans to a term loan, the Facility Termination Date shall mean the one-year anniversary of the Revolving Credit Termination Date.

"Federal Funds Effective Rate" means, for any day, an interest rate per annum equal to the weighted average of the rates on overnight Federal funds transactions with members of the Federal Reserve System arranged by Federal funds brokers on such day, as published for such day (or, if such day is not a Business Day, for the immediately preceding Business Day) by the Federal Reserve Bank of New York, or, if such rate is not so published for any day which is a Business Day, the average of the quotations at approximately 10:00 a.m. (Chicago time) on such day on such transactions received by the Agent from three Federal funds brokers of recognized standing selected by the Agent in its sole discretion.

"Floating Rate" means, for any day, a rate per annum equal to (i) the Alternate Base Rate for such day plus (ii) the Applicable Margin plus (iii) from and after the Loan Conversion Date, the Term Loan Margin, in each case changing when and as the Alternate Base Rate changes.

"Floating Rate Advance" means an Advance which, except as otherwise provided in Section 2.11, bears interest at the Floating Rate.

"Floating Rate Loan" means a Loan which, except as otherwise provided in Section 2.11, bears interest at the Floating Rate.

"Fund" means any Person (other than a natural person) that is (or will be) engaged in making, purchasing, holding or otherwise investing in commercial loans and similar extensions of credit in the ordinary course of its business.

"GAAP" means generally accepted accounting principles in effect from time to time.

"Indebtedness" means, with respect to any Person (without duplication), (a) all indebtedness and obligations of such Person for borrowed money or in respect of loans or advances of any kind, (b) all obligations of such Person evidenced by notes, bonds, debentures or similar instruments, (c) all reimbursement obligations outstanding of such Person with respect to surety bonds, letters of credit and bankers' acceptances, (d) all obligations of such Person to pay the deferred purchase price of property or services (other than accounts payable arising in the ordinary course of such Person's business payable on terms customary in the trade), (e) all indebtedness created or arising under any conditional sale or other title retention agreement with respect to property acquired by such Person,

(f) all Capitalized Lease Obligations of such Person, (g) all obligations and liabilities of such Person incurred in connection with any transaction or series of transactions providing for the financing of assets through one or more securitizations or in connection with, or pursuant to, any synthetic lease or similar off-balance sheet financing, (h) all Contingent Obligations of such Person in respect of the Indebtedness of the types described in clauses (a) — (g) above of another Person, (i) the net termination obligations of such Person under any Rate Management Transaction, calculated as of any date as if such agreement or arrangement were terminated as of such date, (j) the aggregate amount of uncollected accounts receivable of such Person subject at the time of determination to a sale of receivables (or similar transaction) to the extent such transaction is effected with recourse to such Person (whether or not such transaction would be reflected on the balance sheet of such Person in accordance with GAAP) and (k) all indebtedness secured by any Lien on any property or asset owned or held by such Person regardless of whether the indebtedness secured thereby shall have been assumed by such Person or is nonrecourse to the credit of such Person.

"Interest Period" means, with respect to a Eurodollar Advance, a period of one, two, three or six months or such other period agreed to by the Lenders and the Borrower, commencing on a Business Day selected by the Borrower pursuant to this Agreement. Such Interest Period shall end on but exclude the day which corresponds numerically to such date one, two, three or six months or such other agreed upon period thereafter, *provided, however,* that if there is no such numerically corresponding day in such next, second, third or sixth succeeding month or such other succeeding period, such Interest Period shall end on the last Business Day of such next, second, third or sixth succeeding month or such other succeeding period. If an Interest Period would otherwise end on a day which is not a Business Day, such Interest Period shall end on the next succeeding Business Day, *provided, however,* that if said next succeeding Business Day falls in a new calendar month, such Interest Period shall end on the immediately preceding Business Day.

"Lenders" means the lending institutions listed on the signature pages of this Agreement and their respective successors and assigns.

"Lending Installation" means, with respect to a Lender or the Agent, the office, branch, subsidiary or affiliate of such Lender or the Agent listed on the signature pages hereof or on the administrative information sheets provided to the Agent in connection herewith or on a Schedule or otherwise selected by such Lender or the Agent pursuant to Section 2.17.

"Letter of Credit" of a Person means a letter of credit or similar instrument which is issued upon the application of such Person or upon which such Person is an account party or for which such Person is in any way liable.

"Lien" means any lien (statutory or other), mortgage, pledge, hypothecation, assignment, deposit arrangement, encumbrance or preference, priority or other security agreement or preferential arrangement of any kind or nature whatsoever (including, without limitation, the interest of a vendor or lessor under any conditional sale, Capitalized Lease or other title retention agreement).

"Loan" means, with respect to a Lender, such Lender's loan made pursuant to Article II (or any conversion or continuation thereof).

"Loan Conversion Date" is defined in Section 2.1.

"Loan Documents" means this Agreement and all other documents, instruments, notes (including any Notes issued pursuant to Section 2.13 (if requested)) and agreements executed in connection therewith or contemplated thereby, as the same may be amended, restated or otherwise modified and in effect from time to time.

"Material Adverse Effect" means a material adverse effect on (i) the business, Property, condition (financial or otherwise), operations or results of operations of the Borrower and its Subsidiaries taken as a whole, (ii) the ability of the Borrower to perform its obligations under the Loan Documents, or (iii) the validity or enforceability of any of the Loan Documents or the rights or remedies of the Agent or the Lenders thereunder.

"Material Indebtedness" means Indebtedness in an outstanding principal amount of $35,000,000 or more in the aggregate (or the equivalent thereof in any currency other than U.S. dollars).

"Material Indebtedness Agreement" means any agreement under which any Material Indebtedness was created or is governed or which provides for the incurrence of Indebtedness in an amount which would constitute Material Indebtedness (whether or not an amount of Indebtedness constituting Material Indebtedness is outstanding thereunder).

"Material Subsidiary" means any Subsidiary that would be a "significant subsidiary" as defined in Article 1, Rule 1-02 of Regulation S-X, as promulgated under the Securities Act of 1933, as amended, as such regulation is in effect on the date of this Agreement, provided, however, a Subsidiary that would not be a "significant subsidiary" as defined in Regulation S-X will be treated as a Material Subsidiary to the extent necessary so that all Subsidiaries that are not Material Subsidiaries do not in the aggregate represent more than 25% of the consolidated total assets of the Borrower and its consolidated Subsidiaries or more than 25% of the total revenue of the Borrower and its consolidated Subsidiaries.

"Moody's" means Moody's Investors Service, Inc.

"Multiemployer Plan" means a multiemployer plan, as defined in Section 4001(a)(3) of ERISA, which is covered by Title IV of ERISA and to which the Borrower or any member of the Controlled Group is obligated to make contributions.

"Non-U.S. Lender" is defined in Section 3.5(iv).

"Note" is defined in Section 2.13.

"Obligations" means all Loans, advances, debts, liabilities, obligations, covenants and duties owing by the Borrower to the Agent, any Lender, any Arranger, any affiliate of the Agent, any Lender or any Arranger, or any indemnitee under the provisions of Section 9.6 or any other provisions of the Loan Documents, in each case of any kind or nature, arising under this Agreement or any other Loan Document, whether or not evidenced by any note, guaranty or other instrument, whether or not for the payment of money, whether arising by reason of an extension of credit, loan, guaranty, indemnification, or in any other manner, whether direct or indirect (including those acquired by assignment), absolute or contingent, due or to become due, now existing or hereafter arising and however acquired. The term includes, without limitation, all interest, charges, expenses, fees, attorneys' fees and disbursements, and any other sum chargeable to the Borrower or any of its Subsidiaries under this Agreement or any other Loan Document.

“Other Taxes” is defined in Section 3.5(ii).

“Outstanding Credit Exposure” means, as to any Lender, the aggregate principal amount of its Loans outstanding at such time.

“Participants” is defined in Section 12.2.1.

“Payment Date” means the last day of March, June, September and December and the Facility Termination Date.

“PBGC” means the Pension Benefit Guaranty Corporation, or any successor thereto.

“Person” means any natural person, corporation, firm, joint venture, partnership, limited liability company, association, enterprise, trust or other entity or organization, or any government or political subdivision or any agency, department or instrumentality thereof.

“Plan” means an employee pension benefit plan, excluding any Multiemployer Plan, which is covered by Title IV of ERISA or subject to the minimum funding standards under Section 412 of the Code as to which the Borrower or any member of the Controlled Group may have any liability.

“Pricing Schedule” means the Schedule identifying the Applicable Margin and Applicable Fee Rate attached hereto and identified as such.

“Prime Rate” means a rate per annum equal to the prime rate of interest announced from time to time by Bank One or its parent (which is not necessarily the lowest rate charged to any customer), changing when and as said prime rate changes.

“Property” of a Person means any and all property, whether real, personal, tangible, intangible, or mixed, of such Person, or other assets owned, leased or operated by such Person.

“Pro Rata Share” means, with respect to a Lender, a portion equal to a fraction the numerator of which is such Lender’s Commitment at such time (in each case, as adjusted from time to time in accordance with the provisions of this Agreement) and the denominator of which is the Aggregate Commitment at such time, or, if the Aggregate Commitment has been terminated, a fraction the numerator of which is such Lender’s Outstanding Credit Exposure at such time and the denominator of which is the sum of the aggregate outstanding amount of all Loans at such time.

“Purchasers” is defined in Section 12.3.1.

“Rate Management Transaction” means any transaction (including an agreement with respect thereto) now existing or hereafter entered by the Borrower which is a rate swap, basis swap, forward rate transaction, equity or equity index swap, equity or equity index option, bond option, interest rate option, foreign exchange transaction, cap transaction, floor transaction, collar transaction, forward transaction, currency swap transaction, cross-currency rate swap transaction, currency option or any other similar transaction (including any option with respect to any of these transactions) or any combination thereof, whether linked to one or more interest rates, foreign currencies, or equity prices.

“Receivables Purchase Documents” means any series of receivables purchase or sale agreements generally consistent with terms contained in comparable structured finance transactions pursuant to which the Borrower or any of its Subsidiaries, in their respective capacities as sellers or transferors of any consumer loan receivables, sell or transfer to SPVs all of their respective rights, title and interest in and to certain consumer loan receivables for further sale or transfer to other purchasers of or investors in such assets (and the other documents, instruments and agreements executed in connection therewith), as any such agreements may be amended, restated, supplemented or otherwise modified from time to time, or any replacement or substitution therefor.

“Receivables Purchase Facility” means any securitization facility made available to the Borrower or any of its Subsidiaries, pursuant to which consumer loan receivables of the Borrower or any of its Subsidiaries are transferred to one or more SPVs, and thereafter to certain investors, pursuant to the terms and conditions of the Receivables Purchase Documents.

“Regulation D” means Regulation D of the Board of Governors of the Federal Reserve System as from time to time in effect and any successor thereto or other regulation or official interpretation of said Board of Governors relating to reserve requirements applicable to member banks of the Federal Reserve System.

“Regulation U” means Regulation U of the Board of Governors of the Federal Reserve System as from time to time in effect and any successor or other regulation or official

interpretation of said Board of Governors relating to the extension of credit by banks for the purpose of purchasing or carrying margin stocks applicable to member banks of the Federal Reserve System.

“Regulation X” means Regulation X of the Board of Governors of the Federal Reserve System as from time to time in effect and any successor or other regulation or official interpretation of said Board of Governors relating to the extension of credit by foreign lenders for the purpose of purchasing or carrying margin stock (as defined therein).

“Reportable Event” means a reportable event as defined in Section 4043 of ERISA and the regulations issued under such section, with respect to a Plan subject to Title IV of ERISA, excluding, however, such events as to which the PBGC has by regulation waived the requirement of Section 4043(a) of ERISA that it be notified within 30 days of the occurrence of such event, *provided, however,* that a failure to meet the minimum funding standard of Section 412 of the Code and of Section 302 of ERISA shall be a Reportable Event regardless of the issuance of any such waiver of the notice requirement in accordance with either Section 4043(a) of ERISA or Section 412(d) of the Code.

“Required Lenders” means Lenders in the aggregate having greater than fifty percent (50%) of the Aggregate Commitment or, if the Aggregate Commitment has been terminated, Lenders in the aggregate holding greater than fifty percent (50%) of the Aggregate Outstanding Credit Exposure.

“Reserve Requirement” means, with respect to an Interest Period, the maximum aggregate reserve requirement (including all basic, supplemental, marginal and other reserves) which is imposed under Regulation D on Eurocurrency liabilities.

"Revolving Credit Termination Date" means the earlier of (a) December 9, 2004 and (b) the date of termination in whole of the Aggregate Commitment pursuant to Section 2.5 hereof or the Commitments pursuant to Section 8.1 hereof.

"S&P" means Standard and Poor's Ratings Services, a division of The McGraw Hill Companies, Inc.

"Schedule" refers to a specific schedule to this Agreement, unless another document is specifically referenced.

"SEC Reports" means (i) the Annual Report on Form 10-K of the Borrower for the fiscal year ended December 31, 2002, (ii) the Quarterly Reports on Form 10-Q of the Borrower for the fiscal quarters ended March 31, 2003, June 30, 2003 and September 30, 2003 and (iii) the Current Reports on Form 8-K filed by the Borrower prior to the Closing Date.

"Section" means a numbered section of this Agreement, unless another document is specifically referenced.

"Single Employer Plan" means a Plan maintained by the Borrower or any member of the Controlled Group for employees of the Borrower or any member of the Controlled Group.

"SPV" means any special purpose entity established for the purpose of purchasing consumer loan receivables in connection with a receivables securitization transaction permitted under the terms of this Agreement.

"Subsidiary" of a Person means (i) any corporation more than 50% of the outstanding securities having ordinary voting power of which shall at the time be owned or controlled, directly or indirectly, by such Person or by one or more of its Subsidiaries or by such Person and one or more of its Subsidiaries, or (ii) any partnership, limited liability company, association, joint venture or similar business organization more than 50% of the ownership interests having ordinary voting power of which shall at the time be so owned or controlled. Unless otherwise expressly provided, all references herein to a "Subsidiary" shall mean a Subsidiary of the Borrower.

"Substantial Portion" means, with respect to the Property of the Borrower and its Subsidiaries, Property which represents more than 25% of the consolidated assets of the Borrower and its Subsidiaries or property which is responsible for more than 25% of the consolidated net sales or of the consolidated net income of the Borrower and its Subsidiaries, in each case, as would be shown in the consolidated financial statements of the Borrower and its Subsidiaries as at the end of the four fiscal quarter period ending with the fiscal quarter immediately prior to the fiscal quarter in which such determination is made (or if financial statements have not been delivered hereunder for that fiscal quarter which ends the four fiscal quarter period, then the financial statements delivered hereunder for the quarter ending immediately prior to that quarter).

"Syndication Agent" means Wachovia Bank, National Association, in its capacity as Syndication Agent hereunder.

"Taxes" means any and all present or future taxes, duties, levies, imposts, deductions, charges or withholdings, and any and all liabilities with respect to the foregoing, but *excluding* Excluded Taxes and Other Taxes.

"Transferee" is defined in Section 12.4.

"Type" means, with respect to any Advance, its nature as a Floating Rate Advance or a Eurodollar Advance and with respect to any Loan, its nature as a Floating Rate Loan or a Eurodollar Loan.

"Unfunded Liabilities" means the amount (if any) by which the present value of all vested and unvested accrued benefits under each Single Employer Plan subject to Title IV of ERISA exceeds the fair market value of all such Plan's assets allocable to such benefits, all determined as of the then most recent valuation date for such Plan for which a valuation report is available, using actuarial assumptions for funding purposes as set forth in such report.

"Unmatured Default" means an event which but for the lapse of time or the giving of notice, or both, would constitute a Default.

"Utilization Fee" is defined in Section 2.5.2.

"Wholly-Owned Subsidiary" of a Person means (i) any Subsidiary all of the outstanding voting securities of which shall at the time be owned or controlled, directly or indirectly, by such Person or one or more Wholly-Owned Subsidiaries of such Person, or by such Person and one or more Wholly-Owned Subsidiaries of such Person, or (ii) any partnership, limited liability company, association, joint venture or similar business organization 100% of the ownership interests having ordinary voting power of which shall at the time be so owned or controlled.

The foregoing definitions shall be equally applicable to both the singular and plural forms of the defined terms.

ARTICLE II

THE CREDITS

2.1. Commitment; Conversion to Term Loan. From and including the date of this Agreement and prior to the Revolving Credit Termination Date, upon the satisfaction of the conditions precedent set forth in Section 4.1 and 4.2, as applicable, each Lender severally agrees, on the terms and conditions set forth in this Agreement, to make Loans to the Borrower from time to time in an amount not to exceed in the aggregate at any one time outstanding its Pro Rata Share of the Aggregate Commitment; *provided* that at no time shall the Aggregate Outstanding Credit Exposure hereunder exceed the Aggregate Commitment. Subject to the terms of this Agreement, the Borrower may borrow, repay and reborrow at any time prior to the Revolving Credit Termination Date. The commitment of each Lender to lend hereunder shall expire on the Revolving Credit Termination Date. Principal payments made after the Revolving Credit Termination Date may not be reborrowed. If the Borrower so elects by delivery of a written notice to the Agent at least three (3), but not more than ten (10), Business Days prior to the date of the then current Revolving Credit Termination Date, then on such Revolving Credit Termination Date (the "Loan Conversion Date"), (i) the Borrower's option to borrow additional Loans shall terminate, (ii) the Commitments shall be terminated and (iii) the then outstanding principal amount of the Loans shall be converted to a term loan which shall, in the case of each Lender, be in the amount of such Lender's outstanding Loans on such date, and which shall be due and payable in full, together with accrued interest and all other Obligations, on the first anniversary of the Loan Conversion Date, with any prepayment thereof to be made subject to Section 2.7; *provided,* that no such conversion shall occur if a Default or Unmatured Default has occurred and is continuing either on the date of delivery of such notice or on the Loan Conversion Date. Amounts repaid or prepaid following any such conversion may not be reborrowed. If such term loan conversion has not previously been completed, then on the Revolving Credit Termination Date then in effect, the Commitments shall be terminated and all of the Loans and other Obligations shall be due and payable.

2.2. Required Payments; Termination. Any outstanding Advances and all other unpaid Obligations shall be paid in full by the Borrower on the Facility Termination Date. Notwithstanding the termination of this Agreement on the Facility Termination Date, until all of the Obligations (other than contingent indemnity obligations) shall have been fully paid and satisfied and all financing arrangements among the Borrower and the Lenders hereunder and under the other Loan Documents shall have been terminated, all of the rights and remedies under this Agreement and the other Loan Documents shall survive.

2.3. Ratable Loans. Each Advance hereunder shall consist of Loans made from the several Lenders ratably in proportion to the ratio that their respective Commitments bear to the Aggregate Commitment.

2.4. Types of Advances. The Advances may be Floating Rate Advances or Eurodollar Advances, or a combination thereof, selected by the Borrower in accordance with Sections 2.8 and 2.9.

2.5. Facility Fee; Utilization Fee; Reductions in Aggregate Commitment.

2.5.1 Facility Fee. The Borrower agrees to pay to the Agent for the account of each Lender a Facility Fee (the "Facility Fee") at a per annum rate equal to the Applicable Fee Rate on such Lender's Commitment (whether used or unused) from the date hereof to and including the Facility Termination Date, payable on each Payment Date and the Facility Termination Date, provided that, if any Lender continues to have Loans outstanding hereunder after the termination of its Commitment (including, without limitation, during any period when Loans may be outstanding but new Loans may not be borrowed hereunder), then the Facility Fee shall continue to accrue on the aggregate principal amount of the Loans owed to such Lender until the date on which such Loans are repaid in full.

2.5.2 Utilization Fee. For any period occurring prior to the Loan Conversion Date during which the Aggregate Outstanding Credit Exposure of all the Lenders hereunder exceeds thirty-three and one-third percent ($33^{1/3}$%) of the Aggregate Commitment hereunder (which, after the Commitments have been terminated, shall be based on the Aggregate Commitment immediately prior to such termination) then in effect on such date, the Borrower will pay to the Agent for the ratable benefit of the Lenders a utilization fee (the "Utilization Fee") at a per annum rate equal to the Applicable Fee Rate on the average daily Aggregate Outstanding Credit Exposure during such period. The Utilization Fee shall be payable quarterly in arrears on each Payment Date occurring prior to the Loan Conversion Date (if any) and on the earlier of the Loan Conversion Date (if any) and the date this Agreement is terminated in full and all Obligations hereunder have been paid in full pursuant to Section 2.2.

2.5.3. Reductions in Aggregate Commitment. The Borrower may permanently reduce the Aggregate Commitment in whole, or in part, ratably among the Lenders in integral multiples of $5,000,000, upon at least two Business Days' written notice to the Agent, which notice shall specify the amount of any such reduction, *provided, however,* that the amount of the Aggregate Commitment may not be reduced below the aggregate principal amount of the outstanding Advances, after taking into account any prepayments to be made on or before such date. All accrued facility fees shall be payable on the effective date of any termination of the obligations of the Lenders to make Loans hereunder and on the final date upon which all Loans are repaid hereunder.

2.6. Minimum Amount of Each Advance. Each Eurodollar Advance shall be in the minimum amount of $5,000,000 (and in multiples of $1,000,000 if in excess thereof), and each Floating Rate Advance shall be in the minimum amount of $5,000,000 (and in multiples of

$1,000,000 if in excess thereof), *provided, however,* that any Floating Rate Advance may be in the amount of the unused Aggregate Commitment.

2.7. Optional Principal Payments. The Borrower may from time to time pay, without penalty or premium, all outstanding Floating Rate Advances, or, in a minimum aggregate amount of $1,000,000 or any integral multiple of $1,000,000 in excess thereof, any portion of the outstanding Floating Rate Advances on any Business Day upon notice to the Agent by no later than 10:00 a.m. (Chicago time) on the date of such prepayment. The Borrower may from time to time pay, subject to the payment of any funding indemnification amounts required by Section 3.4 but without penalty or premium, all outstanding Eurodollar Advances, or, in a minimum aggregate amount of $1,000,000 or any integral multiple of $500,000 in excess thereof, any portion of the outstanding Eurodollar Advances upon three Business Days' prior notice to the Agent.

2.8. Method of Selecting Types and Interest Periods for New Advances. The Borrower shall select the Type of Advance and, in the case of each Eurodollar Advance, the Interest Period applicable thereto from time to time. The Borrower shall give the Agent irrevocable notice (a "Borrowing Notice") not later than 10:00 a.m. (Chicago time) on the Borrowing Date of each Floating Rate Advance and three Business Days before the Borrowing Date for each Eurodollar Advance, specifying:

2.8.1 the Borrowing Date, which shall be a Business Day, of such Advance,

2.8.2 the aggregate amount of such Advance,

2.8.3 the Type of Advance selected, and

2.8.4 in the case of each Eurodollar Advance, the Interest Period applicable thereto.

Not later than noon (Chicago time) on each Borrowing Date, each Lender shall make available its Loan or Loans in funds immediately available in Chicago to the Agent at its address specified pursuant to Article XIII. The Agent will promptly make the funds so received from the Lenders available to the Borrower at the Agent's aforesaid address.

2.9. Conversion and Continuation of Outstanding Advances. Floating Rate Advances shall continue as Floating Rate Advances unless and until such Floating Rate Advances are converted into Eurodollar Advances pursuant to this Section 2.9 or are repaid in accordance with Section 2.7. Each Eurodollar Advance shall continue as a Eurodollar Advance until the end of the then applicable Interest Period therefor, at which time such Eurodollar Advance shall be automatically converted into a Floating Rate Advance unless (x) such Eurodollar Advance is or was repaid in accordance with Section 2.7 or (y) the Borrower shall have given the Agent a Conversion/Continuation Notice (as defined below) requesting that, at the end of such Interest Period, such Eurodollar Advance continue as a Eurodollar Advance for the same or another Interest Period. Subject to the terms of Section 2.6, the Borrower may elect from time to time to convert all or any part of a Floating Rate Advance into a Eurodollar Advance. The Borrower shall give the Agent irrevocable notice (a "Conversion/Continuation Notice") of each conversion of a Floating Rate Advance into a Eurodollar Advance or continuation of a Eurodollar Advance

not later than 10:00 a.m. (Chicago time) on the third Business Day prior to the date of the requested conversion or continuation, specifying:

2.9.1 the requested date, which shall be a Business Day, of such conversion or continuation,

2.9.2 the aggregate amount and Type of the Advance which is to be converted or continued, and

2.9.3 the amount of such Advance which is to be converted into or continued as a Eurodollar Advance and the duration of the Interest Period applicable thereto.

2.10. Changes in Interest Rate, etc. Each Floating Rate Advance shall bear interest on the outstanding principal amount thereof, for each day from and including the date such Advance is made or is automatically converted from a Eurodollar Advance into a Floating Rate Advance pursuant to Section 2.9, to but excluding the date it is paid or is converted into a Eurodollar Advance pursuant to Section 2.9 hereof, at a rate per annum equal to the Floating Rate for such day. Changes in the rate of interest on that portion of any Advance maintained as a Floating Rate Advance will take effect simultaneously with each change in the Alternate Base Rate. Each Eurodollar Advance shall bear interest on the outstanding principal amount thereof from and including the first day of the Interest Period applicable thereto to (but not including) the last day of such Interest Period at the interest rate determined by the Agent as applicable to such Eurodollar Advance based upon the Borrower's selections under Sections 2.8 and 2.9 and otherwise in accordance with the terms hereof. No Interest Period may end after the Facility Termination Date. The Borrower shall select Interest Periods so that it is not necessary to repay any portion of a Eurodollar Advance prior to the last day of the applicable Interest Period in order to make a mandatory prepayment required pursuant to Section 2.2.

2.11. Rates Applicable After Default. Notwithstanding anything to the contrary contained in Section 2.8, 2.9 or 2.10, during the continuance of a Default or Unmatured Default the Required Lenders may, at their option, by notice to the Borrower, declare that no Advance may be made as, converted into or continued as a Eurodollar Advance. During the continuance of a Default the Required Lenders may, at their option, by notice to the Borrower (which notice may be revoked at the option of the Required Lenders notwithstanding any provision of Section 8.2 requiring unanimous consent of the Lenders to changes in interest rates), declare that (i) each Eurodollar Advance shall bear interest for the remainder of the applicable Interest Period at the rate otherwise applicable to such Interest Period plus 2% per annum and (ii) each Floating Rate Advance shall bear interest at a rate per annum equal to the Floating Rate in effect from time to time plus 2% per annum, *provided* that, during the continuance of a Default under Section 7.6 or 7.7, the interest rates set forth in clauses (i) and (ii) above shall be applicable to all Advances without any election or action on the part of the Agent or any Lender.

2.12. Method of Payment. All payments of the Obligations hereunder shall be made, without setoff, deduction, or counterclaim, in immediately available funds to the Agent at the Agent's address specified pursuant to Article XIII, or at any other Lending Installation of the Agent specified in writing by the Agent to the Borrower, by noon (local time) on the date when due and shall be applied ratably by the Agent among the Lenders. Each payment delivered to the

Agent for the account of any Lender shall be delivered promptly by the Agent to such Lender in the same type of funds that the Agent received at its address specified pursuant to Article XIII or at any Lending Installation specified in a notice received by the Agent from such Lender. The Agent is hereby authorized to charge the account of the Borrower maintained with Bank One for each payment of principal, interest and fees as it becomes due hereunder.

2.13. Noteless Agreement; Evidence of Indebtedness. (i) Each Lender shall maintain in accordance with its usual practice an account or accounts evidencing the indebtedness of the Borrower to such Lender resulting from each Loan made by such Lender from time to time, including the amounts of principal and interest payable and paid to such Lender from time to time hereunder.

(ii) The Agent shall also maintain accounts in which it will record (a) the amount of each Loan made hereunder, the Type thereof and the Interest Period with respect thereto, (b) the amount of any principal or interest due and payable or to become due and payable from the Borrower to each Lender hereunder and (c) the amount of any sum received by the Agent hereunder from the Borrower and each Lender's share thereof.

(iii) The entries maintained in the accounts maintained pursuant to paragraphs (i) and (ii) above shall be *prima facie* evidence of the existence and amounts of the Obligations therein recorded; *provided, however,* that the failure of the Agent or any Lender to maintain such accounts or any error therein shall not in any manner affect the obligation of the Borrower to repay the Obligations in accordance with their terms.

(iv) Any Lender may request that its Loans be evidenced by a promissory note in substantially the form of Exhibit E (a "Note"). In such event, the Borrower shall prepare, execute and deliver to such Lender such Note payable to the order of such Lender. Thereafter, the Loans evidenced by such Note and interest thereon shall at all times (prior to any assignment pursuant to Section 12.3) be represented by one or more Notes payable to the order of the payee named therein, except to the extent that any such Lender subsequently returns any such Note for cancellation and requests that such Loans once again be evidenced as described in paragraphs (i) and (ii) above.

2.14. Telephonic Notices. The Borrower hereby authorizes the Lenders and the Agent to extend, convert or continue Advances, effect selections of Types of Advances and to transfer funds based on telephonic notices made by any person or persons the Agent or any Lender in good faith believes to be acting on behalf of the Borrower, it being understood that the foregoing authorization is specifically intended to allow Borrowing Notices and Conversion/Continuation Notices to be given telephonically. The Borrower agrees to deliver promptly to the Agent a written confirmation, if such confirmation is requested by the Agent or any Lender, of each telephonic notice signed by an Authorized Officer. If the written confirmation differs in any material respect from the action taken by the Agent and the Lenders, the records of the Agent and the Lenders shall govern absent manifest error.

2.15. Interest Payment Dates; Interest and Fee Basis. Interest accrued on each Floating Rate Advance shall be payable in arrears on each Payment Date, commencing with the first such date to occur after the date hereof, on any date on which the Floating Rate Advance is prepaid, whether due to acceleration or otherwise, and at maturity. Interest accrued on that portion of the outstanding principal amount of any Floating Rate Advance converted into a Eurodollar Advance on a day other than a Payment Date shall be payable on the date of conversion. Interest accrued on each Eurodollar Advance shall be payable on the last day of its applicable Interest Period, on any date on which the Eurodollar Advance is prepaid, whether by acceleration or otherwise, and at maturity. Interest accrued on each Eurodollar Advance having an Interest Period longer than three months shall also be payable on the last day of each three-month interval during such Interest Period. Interest and fees shall be calculated for actual days elapsed on the basis of a 360-day year. Interest shall be payable for the day an Advance is made but not for the day of any payment on the amount paid if payment is received prior to noon (local time) at the place of payment. If any payment of principal of or interest on an Advance, any fees or any other amounts payable to the Agent or any Lender hereunder shall become due on a day which is not a Business Day, such payment shall be made on the next succeeding Business Day and, in the case of a principal payment, such extension of time shall be included in computing interest and fees in connection with such payment.

2.16. Notification of Advances, Interest Rates, Prepayments and Commitment Reductions; Availability of Loans. Promptly after receipt thereof, the Agent will notify each Lender of the contents of each Aggregate Commitment reduction notice, Borrowing Notice, Conversion/Continuation Notice, and repayment notice received by it hereunder. The Agent will notify the Borrower and each Lender of the interest rate applicable to each Eurodollar Advance promptly upon determination of such interest rate and will give the Borrower and each Lender prompt notice of each change in the Alternate Base Rate. Not later than 12:00 noon (Chicago time) on each Borrowing Date, each Lender shall make available its Loan or Loans in funds immediately available in Chicago to the Agent at its address specified pursuant to Article XIII. The Agent will promptly make the funds so received from the Lenders available to the Borrower at the Agent's aforesaid address.

2.17. Lending Installations. Each Lender may book its Loans at any Lending Installation selected by such Lender and may change its Lending Installation from time to time. All terms of this Agreement shall apply to any such Lending Installation and the Loans and any Notes issued hereunder shall be deemed held by each Lender for the benefit of any such Lending Installation. Each Lender may, by written notice to the Agent and the Borrower in accordance with Article XIII, designate replacement or additional Lending Installations through which Loans will be made by it and for whose account Loan payments are to be made.

2.18. Non-Receipt of Funds by the Agent. Unless the Borrower or a Lender, as the case may be, notifies the Agent prior to the date on which it is scheduled to make payment to the Agent of (i) in the case of a Lender, the proceeds of a Loan or (ii) in the case of the Borrower, a payment of principal, interest or fees to the Agent for the account of the Lenders, that it does not intend to make such payment, the Agent may assume that such payment has been made. The Agent may, but shall not be obligated to, make the amount of such payment available to the intended recipient in reliance upon such assumption. If such Lender or the Borrower, as the case may be, has not in fact made such payment to the Agent, the recipient of such payment shall, on

demand by the Agent, repay to the Agent the amount so made available together with interest thereon in respect of each day during the period commencing on the date such amount was so made available by the Agent until the date the Agent recovers such amount at a rate per annum equal to (x) in the case of payment by a Lender, the Federal Funds Effective Rate for such day for the first three days and, thereafter, the interest rate applicable to the relevant Loan or (y) in the case of payment by the Borrower, the interest rate applicable to the relevant Loan.

2.19. Replacement of Lender. If the Borrower is required pursuant to Section 3.1, 3.2 or 3.5 to make any additional payment to any Lender or if any Lender's obligation to make or continue, or to convert Floating Rate Advances into, Eurodollar Advances shall be suspended pursuant to Section 3.3 (any Lender so affected an "Affected Lender"), the Borrower may elect, if such amounts continue to be charged or such suspension is still effective, to replace such Affected Lender as a Lender party to this Agreement, *provided* that no Default or Unmatured Default shall have occurred and be continuing at the time of such replacement, and *provided further* that, concurrently with such replacement, (i) another bank or other entity which is reasonably satisfactory to the Borrower and the Agent shall agree, as of such date, to purchase for cash the Loans due to the Affected Lender pursuant to an assignment substantially in the form of Exhibit C and to become a Lender for all purposes under this Agreement and to assume all obligations of the Affected Lender to be terminated as of such date and to comply with the requirements of Section 12.3 applicable to assignments, and (ii) the Borrower shall pay to such Affected Lender in same day funds on the day of such replacement (A) all interest, fees and other amounts then accrued but unpaid to such Affected Lender by the Borrower hereunder to and including the date of termination, including without limitation payments due to such Affected Lender under Sections 3.1, 3.2 and 3.5, and (B) an amount, if any, equal to the payment which would have been due to such Lender on the day of such replacement under Section 3.4 had the Loans of such Affected Lender been prepaid on such date rather than sold to the replacement Lender, in each case to the extent not paid by the purchasing lender.

ARTICLE III

YIELD PROTECTION; TAXES

3.1. Yield Protection. If, on or after the date of this Agreement, the adoption of any law or any governmental or quasi-governmental rule, regulation, policy, guideline or directive (whether or not having the force of law), or any change in any such law, rule, regulation, policy, guideline or directive or in the interpretation or administration thereof by any governmental or quasi-governmental authority, central bank or comparable agency charged with the interpretation or administration thereof, or compliance by any Lender or applicable Lending Installation with any request or directive (whether or not having the force of law) of any such authority, central bank or comparable agency:

3.1.1 subjects any Lender or any applicable Lending Installation to any Taxes, or changes the basis of taxation of payments (other than with respect to Excluded Taxes) to any Lender in respect of its Eurodollar Loans, or

3.1.2 imposes or increases or deems applicable any reserve, assessment, insurance charge, special deposit or similar requirement against assets of, deposits with or

for the account of, or credit extended by, any Lender or any applicable Lending Installation (other than reserves and assessments taken into account in determining the interest rate applicable to Eurodollar Advances), or

3.1.3 imposes any other condition the result of which is to increase the cost to any Lender or any applicable Lending Installation of making, funding or maintaining its Commitment or Eurodollar Loans or reduces any amount receivable by any Lender or any applicable Lending Installation in connection with its Commitment or Eurodollar Loans, or requires any Lender or any applicable Lending Installation to make any payment calculated by reference to the amount of Commitment or Eurodollar Loans held or interest received by it, by an amount deemed material by such Lender,

and the result of any of the foregoing is to increase the cost to such Lender or applicable Lending Installation of making or maintaining its Eurodollar Loans or Commitment or to reduce the return received by such Lender or applicable Lending Installation in connection with such Eurodollar Loans or Commitment, then, within 15 days of demand, accompanied by the written statement required by Section 3.6, by such Lender, the Borrower shall pay such Lender such additional amount or amounts as will compensate such Lender for such increased cost or reduction in amount received.

3.2. Changes in Capital Adequacy Regulations. If a Lender determines the amount of capital required or expected to be maintained by such Lender, any Lending Installation of such Lender or any corporation controlling such Lender is increased as a result of a Change, then, within 15 days of demand, accompanied by the written statement required by Section 3.6, by such Lender, the Borrower shall pay such Lender the amount necessary to compensate for any shortfall in the rate of return on the portion of such increased capital which such Lender determines is attributable to this Agreement, its Loans or its Commitment to make Loans hereunder (after taking into account such Lender's policies as to capital adequacy). "Change" means (i) any change after the date of this Agreement in the Risk-Based Capital Guidelines or (ii) any adoption of, or change in, or change in the interpretation or administration of any other law, governmental or quasi-governmental rule, regulation, policy, guideline, interpretation, or directive (whether or not having the force of law) after the date of this Agreement which affects the amount of capital required or expected to be maintained by any Lender or any Lending Installation or any corporation controlling any Lender. "Risk-Based Capital Guidelines" means (i) the risk-based capital guidelines in effect in the United States on the date of this Agreement, including transition rules, and (ii) the corresponding capital regulations promulgated by regulatory authorities outside the United States implementing the July 1988 report of the Basle Committee on Banking Regulation and Supervisory Practices Entitled "International Convergence of Capital Measurements and Capital Standards," including transition rules, and any amendments to such regulations adopted prior to the date of this Agreement.

3.3. Availability of Types of Advances. If any Lender determines that maintenance of its Eurodollar Loans at a suitable Lending Installation would violate any applicable law, rule, regulation, or directive, whether or not having the force of law, or if the Required Lenders determine that (i) deposits of a type and maturity appropriate to match fund Eurodollar Advances are not available or (ii) the interest rate applicable to Eurodollar Advances does not accurately reflect the cost of making or maintaining Eurodollar Advances, then the Agent shall suspend the

availability of Eurodollar Advances and require any affected Eurodollar Advances to be repaid or converted to Floating Rate Advances on the respective last days of the then current Interest Periods with respect to such Loans or within such earlier period as required by law, subject to the payment of any funding indemnification amounts required by Section 3.4.

3.4. Funding Indemnification. If any payment of a Eurodollar Advance occurs on a date which is not the last day of the applicable Interest Period, whether because of acceleration, prepayment or otherwise, or a Eurodollar Advance is not made on the date specified by the Borrower for any reason other than default by the Lenders, or a Eurodollar Advance is not prepaid on the date specified by the Borrower for any reason, the Borrower will indemnify each Lender for any loss or cost incurred by it resulting therefrom, including, without limitation, any loss or cost in liquidating or employing deposits acquired to fund or maintain such Eurodollar Advance.

3.5. Taxes. (i) All payments by the Borrower to or for the account of any Lender or the Agent hereunder or under any Note shall be made free and clear of and without deduction for any and all Taxes. If the Borrower shall be required by law to deduct any Taxes from or in respect of any sum payable hereunder to any Lender or the Agent, (a) the sum payable shall be increased as necessary so that after making all required deductions (including deductions applicable to additional sums payable under this Section 3.5) such Lender or the Agent (as the case may be) receives an amount equal to the sum it would have received had no such deductions been made, (b) the Borrower shall make such deductions, (c) the Borrower shall pay the full amount deducted to the relevant authority in accordance with applicable law and (d) the Borrower shall furnish to the Agent the original copy of a receipt evidencing payment thereof or, if a receipt cannot be obtained with reasonable efforts, such other evidence of payment as is reasonably acceptable to the Agent, in each case within 30 days after such payment is made.

(ii) In addition, the Borrower shall pay any present or future stamp or documentary taxes and any other excise or property taxes, charges or similar levies which arise from any payment made hereunder or under any Note or from the execution or delivery of, or otherwise with respect to, this Agreement or any Note ("Other Taxes").

(iii) The Borrower shall indemnify the Agent and each Lender for the full amount of Taxes or Other Taxes (including, without limitation, any Taxes or Other Taxes imposed on amounts payable under this Section 3.5) paid by the Agent or such Lender as a result of its Commitment, any Loans made by it hereunder, or otherwise in connection with its participation in this Agreement and any liability (including penalties, interest and expenses) arising therefrom or with respect thereto. Payments due under this indemnification shall be made within 30 days of the date the Agent or such Lender makes demand therefor pursuant to Section 3.6.

(iv) Each Lender that is not incorporated under the laws of the United States of America or a state thereof (each a "Non-U.S. Lender") agrees that it will, not more than ten Business Days after the date on which it becomes a party to this Agreement (but in any event before a payment is due to it hereunder), (i) deliver to each of the Borrower and the Agent two duly completed copies of United

States Internal Revenue Service Form W-8BEN or W-8ECI, certifying in either case that such Lender is entitled to receive payments under this Agreement without deduction or withholding of any United States federal income taxes, or (ii) in the case of a Non-U.S. Lender that is fiscally transparent, deliver to the Agent a United States Internal Revenue Form W-8IMY together with the applicable accompanying forms, W-8 or W-9, as the case may be, and certify that it is entitled to an exemption from United States withholding tax. Each Non-U.S. Lender further undertakes to deliver to each of the Borrower and the Agent (x) renewals or additional copies of such form (or any successor form) on or before the date that such form expires or becomes obsolete, and (y) after the occurrence of any event requiring a change in the most recent forms so delivered by it, such additional forms or amendments thereto as may be reasonably requested by the Borrower or the Agent. All forms or amendments described in the preceding sentence shall certify that such Lender is entitled to receive payments under this Agreement without deduction or withholding of any United States federal income taxes, *unless* an event (including without limitation any change in treaty, law or regulation) has occurred prior to the date on which any such delivery would otherwise be required which renders all such forms inapplicable or which would prevent such Lender from duly completing and delivering any such form or amendment with respect to it and such Lender advises the Borrower and the Agent that it is not capable of receiving payments without any deduction or withholding of United States federal income tax.

(v) For any period during which a Non-U.S. Lender has failed to provide the Borrower with an appropriate form pursuant to clause (iv) above (unless such failure is due to a change in treaty, law or regulation, or any change in the interpretation or administration thereof by any governmental authority, occurring subsequent to the date on which a form originally was required to be provided), such Non-U.S. Lender shall not be entitled to gross up or indemnification under this Section 3.5 with respect to Taxes imposed by the United States; *provided* that, should a Non-U.S. Lender which is otherwise exempt from withholding tax become subject to Taxes because of its failure to deliver a form required under clause (iv) above, the Borrower shall take such steps as such Non-U.S. Lender shall reasonably request to assist such Non-U.S. Lender to recover such Taxes.

(vi) Any Lender that is entitled to an exemption from or reduction of withholding tax with respect to payments under this Agreement or any Note pursuant to the law of any relevant jurisdiction or any treaty shall deliver to the Borrower (with a copy to the Agent), at the time or times prescribed by applicable law, such properly completed and executed documentation prescribed by applicable law as will permit such payments to be made without withholding or at a reduced rate.

(vii) If the U.S. Internal Revenue Service or any other governmental authority of the United States or any other country or any political subdivision thereof asserts a claim that the Agent or the Borrower did not properly withhold tax from amounts paid to or for the account of any Lender (because the appropriate form was not delivered or properly completed, because such Lender failed to notify the Agent

of a change in circumstances which rendered its exemption from withholding ineffective, or for any other reason), such Lender shall indemnify the Agent and the Borrower fully for all amounts paid, directly or indirectly, by the Agent or the Borrower, as the case may be, as tax, withholding therefor, or otherwise, including penalties and interest, and including taxes imposed by any jurisdiction on amounts payable to the Agent or the Borrower, as the case may be, under this subsection, together with all costs and expenses related thereto (including attorneys fees and time charges of attorneys for the Agent or the Borrower, as the case may be, which attorneys may be employees of the Agent or the Borrower, as the case may be). The obligations of the Lenders under this Section 3.5(vii) shall survive the payment of the Obligations and termination of this Agreement.

(viii) In the event that the Borrower makes a payment for the account of any Lender and such Lender, in its reasonable judgment, determines that it has finally and irrevocably received or been granted a credit against or release or remission for, or repayment of, any tax paid or payable by it in respect of or calculated with reference to the deduction or withholding giving rise to such payment, such Lender shall, to the extent that it determines that it can do so without prejudice to the retention of the amount of such credit, relief, remission or repayment, pay to the Borrower such amount as such Lender shall, in its reasonable judgment, have determined to be attributable to such deduction or withholding and which will leave such Lender (after such payment) in no worse position than it would have been in if the Borrower had not been required to make such deduction or withholding. Nothing herein contained shall interfere with the right of a Lender to arrange its tax affairs in whatever manner it thinks fit or oblige any Lender to claim any tax credit or to disclose any information relation to its tax affairs or any computations in respect thereof or require any Lender to do anything that would prejudice its ability to benefit from any other credits, relief, remissions or repayments to which it may be entitled.

3.6. Lender Statements; Survival of Indemnity. Each Lender shall deliver a written statement of such Lender to the Borrower (with a copy to the Agent) as to the amount due, if any, under Section 3.1, 3.2, 3.4 or 3.5. Such written statement shall set forth in reasonable detail the calculations upon which such Lender determined such amount and shall be final, conclusive and binding on the Borrower in the absence of manifest error. Determination of amounts payable under such Sections in connection with a Eurodollar Loan shall be calculated as though each Lender funded its Eurodollar Loan through the purchase of a deposit of the type and maturity corresponding to the deposit used as a reference in determining the Eurodollar Rate applicable to such Loan, whether in fact that is the case or not. Unless otherwise provided herein, the amount specified in the written statement of any Lender shall be payable within 15 days after demand after receipt by the Borrower of such written statement. The obligations of the Borrower under Sections 3.1, 3.2, 3.4 and 3.5 shall survive payment of the Obligations and termination of this Agreement.

3.7. Alternative Lending Installation. To the extent reasonably possible, each Lender shall designate an alternate Lending Installation with respect to its Eurodollar Loans to reduce any liability of the Borrower to such Lender under Sections 3.1, 3.2 and 3.5 or to avoid the

unavailability of Eurodollar Advances under Section 3.3, so long as such designation is not, in the reasonable judgment of such Lender, disadvantageous to such Lender. A Lender's designation of an alternative Lending Installation shall not affect the Borrower's rights under Section 2.19 to replace a Lender.

ARTICLE IV

CONDITIONS PRECEDENT

4.1. Initial Advance. The Lenders shall not be required to make the initial Advance hereunder unless the following conditions precedent have been satisfied and the Borrower has furnished to the Agent sufficient copies for the Lenders of:

4.1.1 Copies of the articles or certificate of incorporation of the Borrower, together with all amendments, and a certificate of good standing, each certified by the appropriate governmental officer in its jurisdiction of incorporation.

4.1.2 Copies, certified by the Secretary or Assistant Secretary of the Borrower, of its by-laws and of its Board of Directors' resolutions and of resolutions or actions of any other body authorizing the execution of the Loan Documents to which the Borrower is a party.

4.1.3 An incumbency certificate, executed by the Secretary or Assistant Secretary of the Borrower, which shall (i) identify by name and title and bear the signatures of the Authorized Officers and any other officers of the Borrower authorized to sign the Loan Documents to which the Borrower is a party, upon which certificate the Agent and the Lenders shall be entitled to rely until informed of any change in writing by the Borrower and (ii) certify as to the tax identification number and business address of the Borrower, as well as any other information reasonably requested in writing by the Agent or any Lender prior to the Closing Date as necessary for the Agent or any Lender to verify the identity of the Borrower as required by Section 326 of the USA PATRIOT ACT.

4.1.4 A certificate, signed by the chief financial officer or treasurer of the Borrower, stating that on the Closing Date no Default or Unmatured Default has occurred and is continuing.

4.1.5 A written opinion of the Borrower's counsels, in form and substance satisfactory to the Agent and addressed to the Lenders, in substantially the form of Exhibit A.

4.1.6 Any Notes requested by a Lender pursuant to Section 2.13 payable to the order of each such requesting Lender.

4.1.7 Written money transfer instructions, in substantially the form of Exhibit D, addressed to the Agent and signed by an Authorized Officer, together with such other related money transfer authorizations as the Agent may have reasonably requested.

4.1.8 The Agent shall have determined that there is an absence of any material adverse change or disruption in primary or secondary loan syndication markets, financial markets or in capital markets generally that would likely impair syndication of the Loans hereunder.

4.1.9 Evidence satisfactory to the Agent that each Existing Credit Agreement has been, or shall simultaneously on the Closing Date be, terminated (except for those provisions that expressly survive the termination thereof) and all loans outstanding and other amounts owed to the respective lenders or agents thereunder shall have been, or simultaneously with the initial Advance hereunder will be, paid in full.

4.1.10 Such other documents as any Lender or its counsel may have reasonably requested.

4.2. Each Advance. The Lenders shall not be required to make any Advance (including the initial Advance hereunder) unless on the applicable Borrowing Date:

4.2.1 There exists no Default or Unmatured Default.

4.2.2 The representations and warranties contained in Article V are true and correct as of such Borrowing Date except to the extent any such representation or warranty is stated to relate solely to an earlier date, in which case such representation or warranty shall have been true and correct on and as of such earlier date; provided that this Section 4.2.2 shall not apply to the representation and warranty set forth in Section 5.5 with respect to an Advance if the proceeds of such Advance will be used exclusively to repay the Borrower's commercial paper (and, in the event of any such Advance, the Agent may require the Borrower to deliver information sufficient to disburse the proceeds of such Advance directly to the holders of such commercial paper or a paying agent therefor).

4.2.3 All legal matters incident to the making of such Advance shall be satisfactory to the Lenders and their counsel.

Each Borrowing Notice with respect to each such Advance shall constitute a representation and warranty by the Borrower that the conditions contained in Sections 4.2.1 and, 4.2.2 have been satisfied. Any Lender may require a duly completed compliance certificate in substantially the form of Exhibit B as a condition to making an Advance.

ARTICLE V

REPRESENTATIONS AND WARRANTIES

The Borrower represents and warrants to the Lenders that:

5.1. Existence and Standing. Each of the Borrower and its Subsidiaries is a corporation, partnership (in the case of Subsidiaries only) or limited liability company duly and properly incorporated or organized, as the case may be, validly existing and (to the extent such concept applies to such entity) in good standing under the laws of its jurisdiction of incorporation

or organization and has all requisite authority to conduct its business in each jurisdiction in which its business is conducted, except where the failure to be in good standing could not reasonably be expected to have a Material Adverse Effect.

5.2. Authorization and Validity. The Borrower has the power and authority and legal right to execute and deliver the Loan Documents and to perform its obligations thereunder. The execution and delivery by the Borrower of the Loan Documents and the performance of its obligations thereunder have been duly authorized by proper corporate proceedings, and the Loan Documents to which the Borrower is a party constitute legal, valid and binding obligations of the Borrower enforceable against the Borrower in accordance with their terms, except as enforceability may be limited by bankruptcy, insolvency or similar laws affecting the enforcement of creditors' rights generally.

5.3. No Conflict; Government Consent. Neither the execution and delivery by the Borrower of the Loan Documents, nor the consummation of the transactions therein contemplated, nor compliance with the provisions thereof will violate (i) any law, rule, regulation, order, writ, judgment, injunction, decree or award binding on the Borrower or any of its Subsidiaries or (ii) the Borrower's or any Subsidiary's articles or certificate of incorporation, partnership agreement, certificate of partnership, articles or certificate of organization, by-laws, or operating or other management agreement, as the case may be, or (iii) the provisions of any indenture, instrument or agreement to which the Borrower or any of its Subsidiaries is a party or is subject, or by which it, or its Property, is bound, or conflict with or constitute a default thereunder, or result in, or require, the creation or imposition of any Lien in, of or on the Property of the Borrower or a Subsidiary pursuant to the terms of any such indenture, instrument or agreement, except for any such violations, conflicts or defaults which, individually and in the aggregate, could not reasonably be expected to have a Material Adverse Effect. No order, consent, adjudication, approval, license, authorization, or validation of, or filing, recording or registration with, or exemption by, or other action in respect of any governmental or public body or authority, or any subdivision thereof, which has not been obtained by the Borrower or any of its Subsidiaries, is required to be obtained by the Borrower or any of its Subsidiaries in connection with the execution and delivery of the Loan Documents, the borrowings under this Agreement, the payment and performance by the Borrower of the Obligations or the legality, validity, binding effect or enforceability of any of the Loan Documents.

5.4. Financial Statements. The December 31, 2002 consolidated financial statements of the Borrower and its Subsidiaries heretofore delivered to the Lenders were prepared in accordance with generally accepted accounting principles in effect on the date such statements were prepared and fairly present the consolidated financial condition and operations of the Borrower and its Subsidiaries at such date and the consolidated results of their operations for the period then ended.

5.5. Material Adverse Change. Since December 31, 2002, except as disclosed in the SEC Reports, there has been no change in the business, Property, condition (financial or otherwise) or results of operations of the Borrower and its Subsidiaries which could reasonably be expected to have a Material Adverse Effect.

5.6. Taxes. The Borrower and its Subsidiaries have filed all United States federal tax returns and all other tax returns which are required to be filed and have paid all taxes due pursuant to said returns or pursuant to any assessment received by the Borrower or any of its Subsidiaries, except in respect of such taxes, if any, (i) which are not in the aggregate material or (ii) as are being contested in good faith and as to which adequate reserves have been provided in accordance with GAAP and as to which no Lien exists (except as permitted by Section 6.12.1). The United States income tax returns of the Borrower and its Subsidiaries have been audited by the Internal Revenue Service through the fiscal year ended December 31, 2000. The charges, accruals and reserves on the books of the Borrower and its Subsidiaries in respect of any taxes or other governmental charges are adequate.

5.7. Litigation and Contingent Obligations. Except as disclosed in the SEC Reports, there is no litigation, arbitration, governmental investigation, proceeding or inquiry pending or, to the knowledge of any of their officers, threatened against or affecting the Borrower or any of its Subsidiaries which could reasonably be expected to have a Material Adverse Effect or which seeks to prevent, enjoin or delay the making of any Loans. Except as disclosed in the SEC Reports, other than any liability incident to any litigation, arbitration or proceeding which could not reasonably be expected to have a Material Adverse Effect, the Borrower has no material contingent obligations not provided for or disclosed in the financial statements referred to in Section 5.4.

5.8. Subsidiaries. Schedule 1 contains an accurate list of all Subsidiaries of the Borrower as of the date of this Agreement, setting forth their respective jurisdictions of organization and the percentage of their respective capital stock or other ownership interests owned by the Borrower or other Subsidiaries. All of the issued and outstanding shares of capital stock or other ownership interests of such Subsidiaries have been (to the extent such concepts are relevant with respect to such ownership interests) duly authorized and issued and are fully paid and non-assessable.

5.9. ERISA. The Unfunded Liabilities of all Single Employer Plans could not in the aggregate reasonably be expected to have a Material Adverse Effect. Neither the Borrower nor any other member of the Controlled Group has incurred, or is reasonably expected to incur, pursuant to Section 4201 of ERISA, any withdrawal liability to Multiemployer Plans in excess of $35,000,000 in the aggregate that has not been satisfied. Each Plan complies in all material respects with all applicable requirements of law and regulations, except for noncompliance that, in the aggregate, would not have a Material Adverse Effect. No Reportable Event has occurred with respect to any Plan, other than those that, in aggregate, would not have a Material Adverse Effect. Except for any such withdrawal, reorganization or termination which would not have a Material Adverse Effect, neither the Borrower nor any other member of the Controlled Group has withdrawn from any Multiemployer Plan within the meaning of Title IV of ERISA or initiated steps to do so, and, to the knowledge of the Borrower, no steps have been taken to reorganize or terminate, within the meaning of Title IV of ERISA, any Multiemployer Plan.

5.10. Accuracy of Information. The information, exhibits or reports furnished by the Borrower to the Agent or to any Lender in connection with the negotiation of, or compliance with, the Loan Documents, taken as a whole, do not contain any material misstatement of fact or

omit to state a material fact or any fact necessary to make the statements contained therein not misleading.

5.11. Regulation U. Neither the Borrower nor any of its Subsidiaries is engaged principally, or as one of its important activities, in the business of extending credit for the purpose, whether immediate, incidental or ultimate of buying or carrying margin stock (as defined in Regulation U), and after applying the proceeds of each Advance, margin stock (as so defined) constitutes less than 25% of the value of those assets of the Borrower and its Subsidiaries which are subject to any limitation on sale, pledge, or other restriction hereunder.

5.12. Material Agreements. Neither the Borrower nor any Subsidiary is a party to any agreement or instrument or subject to any charter or other corporate restriction which could reasonably be expected to have a Material Adverse Effect. Neither the Borrower nor any Subsidiary is in default in the performance, observance or fulfillment of any of the obligations, covenants or conditions contained in (i) any agreement to which it is a party, which default could reasonably be expected to have a Material Adverse Effect or (ii) any Material Indebtedness Agreement.

5.13. Compliance With Laws. The Borrower and its Subsidiaries have complied with all applicable statutes, rules, regulations, orders and restrictions of any domestic or foreign government or any instrumentality or agency thereof having jurisdiction over the conduct of their respective businesses or the ownership of their respective Property except for any failure to comply with any of the foregoing which could not reasonably be expected to have a Material Adverse Effect.

5.14. Ownership of Properties. Except (i) for assets disposed of in the ordinary course of business since September 30, 2003, (ii) as described in SEC Reports and (iii) as set forth on Schedule 2, on the date of this Agreement, the Borrower and its Subsidiaries have good title, free of all Liens other than those permitted by Section 6.12, to all of the assets reflected in the Borrower's consolidated balance sheet as of September 30, 2003, as owned by the Borrower and its Subsidiaries.

5.15. Plan Assets; Prohibited Transactions. The Borrower is not an entity deemed to hold "plan assets" within the meaning of 29 C.F.R. 2510.3-101 of an employee benefit plan (as defined in Section 3(3) of ERISA) which is subject to Title I of ERISA or any plan (within the meaning of Section 4975 of the Code), and assuming the accuracy of the representations and warranties made in Section 9.12 and in any assignment made pursuant to Section 12.3.3, neither the execution of this Agreement nor the making of Loans hereunder gives rise to a non-exempt prohibited transaction within the meaning of Section 406 of ERISA or Section 4975 of the Code.

5.16. Environmental Matters. In the ordinary course of its business, the officers of the Borrower consider the effect of Environmental Laws on the business of the Borrower and its Subsidiaries, in the course of which they identify and evaluate potential risks and liabilities accruing to the Borrower due to Environmental Laws. On the basis of this consideration, the Borrower has concluded that, except as disclosed in the SEC Reports, Environmental Laws cannot reasonably be expected to have a Material Adverse Effect. Except as disclosed in the SEC Reports, neither the Borrower nor any Subsidiary has received any notice to the effect that its

operations are not in material compliance with any of the requirements of applicable Environmental Laws or are the subject of any federal or state investigation evaluating whether any remedial action is needed to respond to a release of any toxic or hazardous waste or substance into the environment, which non-compliance or remedial action could reasonably be expected to have a Material Adverse Effect.

5.17. Investment Company Act. Neither the Borrower nor any Subsidiary is an "investment company" or a company "controlled" by an "investment company", within the meaning of the Investment Company Act of 1940, as amended.

5.18. Public Utility Holding Company Act. The Borrower is a "holding company", as such term is defined in the Public Utility Holding Company Act of 1935, as amended (the "1935 Act"), and the Borrower is currently exempt from the provisions of the 1935 Act (except Section 9 thereof).

5.19. Insurance. The Borrower maintains, and has caused each Subsidiary to maintain, with financially sound and reputable insurance companies insurance on all their Property in such amounts, subject to such deductibles and self-insurance retentions and covering such risks as is consistent with sound business practice of similarly situated companies.

5.20. No Default or Unmatured Default. No Default or Unmatured Default has occurred and is continuing.

5.21. Reportable Transaction. As of the Closing Date, the Borrower does not intend to treat the Advances and related transactions as being a "reportable transaction" (within the meaning of Treasury Regulation Section 1.6011-4). In the event the Borrower determines to take any action inconsistent with such intention, it will promptly notify the Agent thereof.

ARTICLE VI

COVENANTS

During the term of this Agreement, unless the Required Lenders shall otherwise consent in writing:

6.1. Financial Reporting. The Borrower will maintain, for itself and each Subsidiary, a system of accounting established and administered in accordance with generally accepted accounting principles, and furnish to the Lenders:

6.1.1 Within 90 days after the close of each of its fiscal years, financial statements prepared in accordance GAAP on a consolidated basis for itself and its Subsidiaries, including balance sheets as of the end of such period, statements of income and statements of cash flows, accompanied by (a) an audit report, unqualified as to scope, of a nationally recognized firm of independent public accountants or other independent public accountants reasonably acceptable to the Required Lenders; (b) any management letter prepared by said accountants, and (c) a certificate of said accountants that, in the course of their examination necessary for their certification of the foregoing, they have obtained no knowledge of any Default or Unmatured Default, or if, in the opinion of such

accountants, any Default or Unmatured Default shall exist, stating the nature and status thereof.

6.1.2 Within 45 days after the close of the first three quarterly periods of each of its fiscal years, for itself and its Subsidiaries, consolidated unaudited balance sheets as at the close of each such period and consolidated statements of income and a statement of cash flows for the period from the beginning of such fiscal year to the end of such quarter, all certified by its chief financial officer or treasurer.

6.1.3 Together with the financial statements required under Sections 6.1(i) and (ii), a compliance certificate in substantially the form of Exhibit B signed by its chief financial officer or treasurer showing the calculations necessary to determine compliance with this Agreement and stating that no Default or Unmatured Default exists, or if any Default or Unmatured Default exists, stating the nature and status thereof.

6.1.4 If requested, within 270 days after the close of each fiscal year of the Borrower, a copy of the actuarial report showing the Unfunded Liabilities of each Single Employer Plan as of the valuation date occurring in such fiscal year, certified by an actuary enrolled under ERISA.

6.1.5 As soon as possible and in any event within 10 days after the Borrower knows that any Reportable Event has occurred with respect to any Plan that could reasonably be expected to have a Material Adverse Effect, a statement, signed by the chief financial officer or treasurer of the Borrower, describing said Reportable Event and the action which the Borrower proposes to take with respect thereto.

6.1.6 As soon as possible and in any event within 10 days after receipt by the Borrower, a copy of (a) any notice or claim to the effect that the Borrower or any of its Subsidiaries is or may be liable to any Person as a result of the release by the Borrower, any of its Subsidiaries, or any other Person of any toxic or hazardous waste or substance into the environment, and (b) any notice alleging any violation of any federal, state or local environmental, health or safety law or regulation by the Borrower or any of its Subsidiaries, which, in either case, could reasonably be expected to have a Material Adverse Effect.

6.1.7 Promptly upon the filing thereof, copies of all registration statements (other than any registration statement on Form S-8 and any registration statement in connection with a dividend reinvestment plan, shareholder purchase plan or employee benefit plan) and annual, quarterly, monthly or other regular reports which the Borrower or any of its Subsidiaries files with the Securities and Exchange Commission.

6.1.8 Such other information (including non-financial information) as the Agent or any Lender may from time to time reasonably request.

6.2. Use of Proceeds. The Borrower will, and will cause each Subsidiary to, use the proceeds of the Advances for general corporate purposes, including without limitation commercial paper liquidity support. The Borrower shall use the proceeds of the Advances in compliance with all applicable legal and regulatory requirements and any such use shall not

result in a violation of any such requirements, including, without limitation, Regulation U and X, the Securities Act of 1933, as amended, and the Securities Exchange Act of 1934, as amended, and the regulations promulgated thereunder.

6.3. Notice of Default. The Borrower will, and will cause each Subsidiary to, give prompt notice in writing to the Lenders of the occurrence of any Default or Unmatured Default and of any other development, financial or otherwise, which could reasonably be expected to have a Material Adverse Effect.

6.4. Conduct of Business. The Borrower will, and will cause each Subsidiary to, be primarily engaged in energy-related businesses and/or other businesses as are ancillary thereto.

6.5. Taxes. The Borrower will, and will cause each Subsidiary to, timely file complete and correct United States federal and applicable foreign, state and local tax returns required by law and pay when due all taxes, assessments and governmental charges and levies upon it or its income, profits or Property, except those (i) which are not in the aggregate material or (ii) which are being contested in good faith by appropriate proceedings and with respect to which adequate reserves have been set aside in accordance with GAAP.

6.6. Insurance. The Borrower will, and will cause each Subsidiary to, maintain with financially sound and reputable insurance companies insurance on all their Property in such amounts, subject to such deductibles and self-insurance retentions, and covering such risks as is consistent with sound business practice, and the Borrower will furnish to any Lender upon request full information as to the insurance carried.

6.7. Compliance with Laws. The Borrower will, and will cause each Subsidiary to, comply with all laws, rules, regulations, orders, writs, judgments, injunctions, decrees or awards to which it may be subject including, without limitation, all Environmental Laws, except where failure to so comply could not reasonably be expected to result in a Material Adverse Effect.

6.8. Maintenance of Properties. Subject to Section 6.11, the Borrower will, and will cause each Subsidiary to, do all things necessary to maintain, preserve, protect and keep its Property used in the operation of its business in good repair, working order and condition, and make all necessary and proper repairs, renewals and replacements so that its business carried on in connection therewith may be properly conducted at all times.

6.9. Inspection; Keeping of Books and Records. The Borrower will, and will cause each Subsidiary to, permit the Agent and the Lenders, by their respective representatives and agents, to inspect any of the Property, books and financial records of the Borrower and each Subsidiary, to examine and make copies of the books of accounts and other financial records of the Borrower and each Subsidiary, and to discuss the affairs, finances and accounts of the Borrower and each Subsidiary with, and to be advised as to the same by, their respective officers at such reasonable times and intervals as the Agent or any Lender may designate. The Borrower shall keep and maintain, and cause each of its Subsidiaries to keep and maintain, in all material respects, proper books of record and account in which entries in conformity with GAAP shall be made of all dealings and transactions in relation to their respective businesses and activities. If a

Default has occurred and is continuing, the Borrower, upon the Agent's request, shall turn over copies of any such records to the Agent or its representatives.

6.10. Merger. The Borrower will not, nor will it permit any Subsidiary to, merge or consolidate with or into any other Person, except that a Subsidiary may merge into the Borrower or a Wholly-Owned Subsidiary and any Subsidiary may merge into any other corporation if after giving effect thereto the survivor is no longer a Subsidiary of the Borrower and the assets of such Subsidiary could have been sold pursuant to the provisions of Section 6.11 if such transaction were treated as a disposition of the assets of such Subsidiary.

6.11. Sale of Assets. The Borrower will not, nor will it permit any Subsidiary to, lease, sell or otherwise dispose of its Property to any other Person, except:

6.11.1 Sales of inventory in the ordinary course of business.

6.11.2 A disposition of assets by a Subsidiary to the Borrower or another Subsidiary or by the Borrower to a Subsidiary.

6.11.3 A disposition of obsolete property, property no longer used in business or other assets in the ordinary course of business of the Borrower or any Subsidiary.

6.11.4 A disposition of assets for an aggregate purchase price of up to $50,000,000 pursuant to, and in accordance with, Receivables Purchase Facilities.

6.11.5 Leases, sales or other dispositions of its Property that, together with all other Property of the Borrower and its Subsidiaries previously leased, sold or disposed of (other than dispositions otherwise permitted by this Section 6.11) as permitted by this Section during the twelve-month period ending with the month in which any such lease, sale or other disposition occurs, do not constitute a Substantial Portion of the Property of the Borrower and its Subsidiaries.

6.12. Liens. The Borrower will not, nor will it permit any Subsidiary to, create, incur, or suffer to exist any Lien in, of or on the Property of the Borrower or any of its Subsidiaries, except:

6.12.1 Liens for taxes, assessments or governmental charges or levies on its Property if the same shall not at the time be delinquent or thereafter can be paid without penalty, or are being contested in good faith and by appropriate proceedings and for which adequate reserves in accordance with GAAP shall have been set aside on its books.

6.12.2 Liens imposed by law, such as carriers', warehousemen's and mechanics' liens and other similar Liens arising in the ordinary course of business which secure payment of obligations not more than 60 days past due or which are being contested in good faith by appropriate proceedings and for which adequate reserves in accordance with GAAP shall have been set aside on its books.

6.12.3 Liens arising out of pledges or deposits under worker's compensation laws, unemployment insurance, old age pensions, or other social security or retirement benefits, or similar legislation.

6.12.4 Liens existing on the date hereof and described in Schedule 3.

6.12.5 Deposits securing liability to insurance carriers under insurance or self-insurance arrangements.

6.12.6 Deposits to secure the performance of bids, trade contracts (other than for borrowed money), leases, statutory obligations, surety and appeal bonds, performance bonds and other obligations of a like nature incurred in the ordinary course of business.

6.12.7 Easements, reservations, rights-of-way, restrictions, survey exceptions and other similar encumbrances as to real property of the Borrower and its Subsidiaries which customarily exist on properties of corporations engaged in similar activities and similarly situated and which do not materially interfere with the conduct of the business of the Borrower or such Subsidiary conducted at the property subject thereto.

6.12.8 Liens existing on property or assets at the time of acquisition thereof by the Borrower or a Subsidiary, provided that (i) such Liens existed at the time of such acquisition and were not created in anticipation thereof, and (ii) any such Lien does not encumber any other property or assets (other than additions thereto and property in replacement or substitution thereof).

6.12.9 Liens existing on property or assets of a Person which becomes a Subsidiary of the Borrower; provided that (i) such Liens existed at the time such Person became a Subsidiary and were not created in anticipation thereof, and (ii) any such Lien does not encumber any other property or assets (other than additions thereto and property in replacement or substitution thereof).

6.12.10 Liens arising by reason of any judgment, decree or order of any court or other governmental authority, if appropriate legal proceedings are being diligently prosecuted and shall not have been finally terminated or the period within which such proceedings may be initiated shall not have expired, in an aggregate amount not to exceed $35,000,000 at any time outstanding.

6.12.11 Leases and subleases of real property owned or leased by the Borrower or any Subsidiary not interfering with the ordinary conduct of the business of the Borrower and the Subsidiaries.

6.12.12 Liens securing Indebtedness (including Capitalized Lease Obligations) of the Borrower and its Subsidiaries incurred to finance the acquisition, repair, construction, development or improvement of fixed or capital assets; provided that (i) such Liens shall be created substantially simultaneously with or within 18 months of the acquisition or completion of repair, construction, development or improvement of such fixed or capital assets and (ii) such Liens do not encumber any property other than the property financed

by such Indebtedness (other than additions thereto and property in replacement or substitution thereof).

6.12.13 Liens in favor of the United States of America or any state thereof, or any department, agency or instrumentality or political subdivision of the United States of America or any state thereof, or for the benefit of holders of securities issued by any such entity, to secure any Indebtedness incurred for the purpose of financing all or any part of the purchase price of the cost of the repair, construction, development or improvement of any fixed or capital assets; provided that such Liens do not encumber any property other than the property financed by such Indebtedness (other than additions thereto and property in replacement or substitution thereof).

6.12.14 Liens securing Indebtedness of the Borrower to a Subsidiary or of a Subsidiary to the Borrower or another Subsidiary.

6.12.15 Liens arising in connection with a Receivables Purchase Facility.

6.12.16 Liens created or assumed by a Subsidiary on any contract for the sale of any product or service or any proceeds therefrom (including accounts and other receivables) related to the operation or use of any acquired property and created not later than 18 months after the later of the date such acquisition or the commencement of full operation of such property.

6.12.17 Liens created by a Subsidiary on advance payment obligations by such Subsidiary to secure indebtedness incurred to finance advances for oil, gas hydrocarbon and other mineral exploration and development.

6.12.18 Cash collateral and other Liens securing obligations of any Subsidiary incurred in the ordinary course of its energy marketing business.

6.12.19 Liens securing obligations, neither assumed by the Borrower or any Subsidiary nor on account of which the Borrower or any Subsidiary customarily pays interest, upon real estate or under which any Subsidiary has a right-of-way, easement, franchise or other servitude or of which any Subsidiary is the lessee of the whole thereof or any interest therein for the purpose of locating pipe lines, substations, measuring stations, tanks, pumping or delivery equipment or similar equipment.

6.12.20 Liens arising by virtue of any statutory or common law provision relating to banker’s liens, rights of setoff or similar rights as to deposit accounts or other funds maintained with a depository institution.

6.12.21 Renewals, extensions and replacements of the Liens permitted under Sections 6.12.4, 6.12.8, 6.12.9, 6.12.12, 6.12.13, 6.12.16 and 6.12.17 above; provided that no such Lien shall as a result thereof cover any additional assets (other than additions thereto and property in replacement or substitution thereof).

6.12.22 Liens not described in Sections 6.12.1 through 6.12.21, inclusive, securing Indebtedness of the Borrower (other than Indebtedness of the Borrower owed to

any Subsidiary) and/or securing Indebtedness of the Borrower’s Subsidiaries (other than Indebtedness of any Subsidiary owed to the Borrower or any other Subsidiary), in an aggregate outstanding amount not to exceed ten percent (10%) of the consolidated assets of the Borrower and its Subsidiaries at the time of such incurrence.

6.13. Affiliates. The Borrower will not, and will not permit any Subsidiary to, enter into any transaction (including, without limitation, the purchase or sale of any Property or service) with, or make any payment or transfer to, any Affiliate (other than the Borrower and its Subsidiaries) except in the ordinary course of business and pursuant to the reasonable requirements of the Borrower's or such Subsidiary's business and upon fair and reasonable terms no less favorable to the Borrower or such Subsidiary than the Borrower or such Subsidiary would obtain in a comparable arms-length transaction.

6.14. Financial Contracts. The Borrower will not, nor will it permit any Subsidiary to, enter into or remain liable upon any Rate Management Transactions except for those entered into in the ordinary course of business for bona fide hedging purposes and not for speculative purposes.

6.15. Leverage Ratio. The Borrower will not permit the ratio, determined as of the end of each of its fiscal quarters, of (i) Consolidated Indebtedness to (ii) Consolidated Capitalization to be greater than 0.65 to 1.0.

6.16. Interest Coverage Ratio. The Borrower will not permit the ratio, determined as of the end of each of its fiscal quarters, of (i) Consolidated EBITDA for the period of four consecutive fiscal quarters ending on the last day of such fiscal quarter to (ii) Consolidated Interest Expense for such period to be less than 3.0 to 1.0.

ARTICLE VII

DEFAULTS

The occurrence of any one or more of the following events shall constitute a Default:

7.1. Any representation or warranty made or deemed made by or on behalf of the Borrower or any of its Subsidiaries to the Lenders or the Agent under or in connection with this Agreement, any Loan, or any certificate or information delivered in connection with this Agreement or any other Loan Document shall be materially false on the date as of which made.

7.2. Nonpayment of principal of any Loan when due, or nonpayment of interest upon any Loan or of any fee or other obligations under any of the Loan Documents within five (5) Business Days after the same becomes due.

7.3. The breach by the Borrower of any of the terms or provisions of Section 6.2, 6.10, 6.11, 6.12, 6.13, 6.14, 6.15 or 6.16.

7.4. The breach by the Borrower (other than a breach which constitutes a Default under another Section of this Article VII) of any of the terms or provisions of this Agreement which is not remedied within five days after written notice from the Agent or any Lender.

7.5. Failure of the Borrower or any of its Subsidiaries to pay when due any Material Indebtedness; or the default by the Borrower or any of its Subsidiaries in the performance (beyond the applicable grace period with respect thereto, if any) of any term, provision or condition contained in any Material Indebtedness Agreement, or any other event shall occur or condition exist, the effect of which default, event or condition is to cause, or to permit the holder(s) of such Material Indebtedness or the lender(s) under any Material Indebtedness Agreement to cause, such Material Indebtedness to become due prior to its stated maturity or any commitment to lend under any Material Indebtedness Agreement to be terminated prior to its stated expiration date; or any Material Indebtedness of the Borrower or any of its Subsidiaries shall be declared to be due and payable or required to be prepaid or repurchased (other than by a regularly scheduled payment) prior to the stated maturity thereof; or the Borrower or any of its Subsidiaries shall not pay, or admit in writing its inability to pay, its debts generally as they become due.

7.6. The Borrower or any of its Material Subsidiaries shall (i) have an order for relief entered with respect to it under the Federal bankruptcy laws as now or hereafter in effect, (ii) make an assignment for the benefit of creditors, (iii) apply for, seek, consent to, or acquiesce in, the appointment of a receiver, custodian, trustee, examiner, liquidator or similar official for it or any Substantial Portion of its Property, (iv) institute any proceeding seeking an order for relief under the Federal bankruptcy laws as now or hereafter in effect or seeking to adjudicate it a bankrupt or insolvent, or seeking dissolution, winding up, liquidation, reorganization, arrangement, adjustment or composition of it or its debts under any law relating to bankruptcy, insolvency or reorganization or relief of debtors, (v) take any corporate or partnership action to authorize or effect any of the foregoing actions set forth in this Section 7.6 or (vi) fail to contest in good faith any appointment or proceeding described in Section 7.7.

7.7. Without the application, approval or consent of the Borrower or any of its Material Subsidiaries, a receiver, trustee, examiner, liquidator or similar official shall be appointed for the Borrower or any of its Material Subsidiaries or any Substantial Portion of its Property, or a proceeding described in Section 7.6(iv) shall be instituted against the Borrower or any of its Material Subsidiaries and such appointment continues undischarged or such proceeding continues undismissed or unstayed for a period of 60 consecutive days.

7.8. Any court, government or governmental agency shall condemn, seize or otherwise appropriate, or take custody or control of, all or any portion of the Property of the Borrower and its Subsidiaries which, when taken together with all other Property of the Borrower and its Subsidiaries so condemned, seized, appropriated, or taken custody or control of, during the twelve-month period ending with the month in which any such action occurs, constitutes a Substantial Portion.

7.9. The Borrower or any of its Subsidiaries shall fail within 45 days to pay, bond or otherwise discharge one or more (i) judgments or orders for the payment of money in excess of $35,000,000 (or the equivalent thereof in currencies other than U.S. Dollars) in the aggregate, or (ii) nonmonetary judgments or orders which, individually or in the aggregate, could reasonably be expected to have a Material Adverse Effect, which judgment(s), in any such case, is/are not stayed on appeal or otherwise being appropriately contested in good faith and with respect to which adequate reserves have not been set aside on its books in accordance with GAAP.

7.10. The Unfunded Liabilities of all Single Employer Plans could in the aggregate reasonably be expected to result in a Material Adverse Effect or any Reportable Event shall occur in connection with any Plan that could reasonably be expected to have a Material Adverse Effect.

7.11. Any Change in Control shall occur.

7.12. The Borrower or any other member of the Controlled Group shall have been notified by the sponsor of a Multiemployer Plan that it has incurred, pursuant to Section 4201 of ERISA, withdrawal liability to such Multiemployer Plan in an amount which, when aggregated with all other amounts required to be paid to Multiemployer Plans by the Borrower or any other member of the Controlled Group as withdrawal liability (determined as of the date of such notification), exceeds $35,000,000 or requires payments exceeding $10,000,000 per annum.

7.13. The Borrower or any other member of the Controlled Group shall have been notified by the sponsor of a Multiemployer Plan that such Multiemployer Plan is in reorganization or is being terminated, within the meaning of Title IV of ERISA, if as a result of such reorganization or termination the aggregate annual contributions of the Borrower and the other members of the Controlled Group (taken as a whole) to all Multiemployer Plans which are then in reorganization or being terminated have been or will be increased, in the aggregate, over the amounts contributed to such Multiemployer Plans for the respective plan years of such Multiemployer Plans immediately preceding the plan year in which the reorganization or termination occurs by an amount exceeding $35,000,000.

7.14. The Borrower or any of its Subsidiaries shall (i) be the subject of any proceeding or investigation pertaining to the release by the Borrower, any of its Subsidiaries or any other Person of any toxic or hazardous waste or substance into the environment, or (ii) violate any Environmental Law, which, in the case of an event described in clause (i) or clause (ii), has resulted in a judgment or order of liability against the Borrower or any of its Subsidiaries in an amount in excess of $35,000,000, which liability is not paid, bonded or otherwise discharged within 45 days or which is not stayed on appeal and being appropriately contested in good faith.

7.15. Any Loan Document shall fail to remain in full force or effect or any action shall be taken by the Borrower or any Subsidiary to discontinue or to assert the invalidity or unenforceability of any Loan Document.

ARTICLE VIII

ACCELERATION, WAIVERS, AMENDMENTS AND REMEDIES

8.1. Acceleration. If any Default described in Section 7.6 or 7.7 occurs with respect to the Borrower, the obligations of the Lenders to make Loans hereunder shall automatically terminate and the Obligations shall immediately become due and payable without any election or action on the part of the Agent or any Lender. If any other Default occurs, the Required Lenders (or the Agent with the consent of the Required Lenders) may terminate or suspend the obligations of the Lenders to make Loans hereunder, or declare the Obligations to be due and payable, or both, whereupon the Obligations shall become immediately due and payable, without

presentment, demand, protest or notice of any kind, all of which the Borrower hereby expressly waives.

If, after acceleration of the maturity of the Obligations or termination of the obligations of the Lenders to make Loans hereunder as a result of any Default (other than any Default as described in Section 7.6 or 7.7 with respect to the Borrower) and before any judgment or decree for the payment of the Obligations due shall have been obtained or entered, the Required Lenders (in their sole discretion) shall so direct, the Agent shall, by notice to the Borrower, rescind and annul such acceleration and/or termination.

8.2. Amendments. Subject to the provisions of this Section 8.2, the Required Lenders (or the Agent with the consent in writing of the Required Lenders) and the Borrower may enter into agreements supplemental hereto for the purpose of adding or modifying any provisions to the Loan Documents or changing in any manner the rights of the Lenders or the Borrower hereunder or waiving any Default hereunder; *provided, however,* that no such supplemental agreement shall, without the consent of all of the Lenders:

8.2.1 Extend the final maturity of any Loan or postpone any regularly scheduled payment of principal of any Loan or forgive all or any portion of the principal amount thereof, or reduce the rate or extend the time of payment of interest or fees thereon (other than a waiver of the application of the default rate of interest pursuant to Section 2.11 hereof).

8.2.2 Reduce the percentage specified in the definition of Required Lenders or any other percentage of Lenders specified to be the applicable percentage in this Agreement to act on specified matters or amend the definition of “Pro Rata Share”.

8.2.3 Extend the Facility Termination Date or the Revolving Credit Termination Date, or reduce the amount or extend the payment date for, the mandatory payments required under Section 2.2, or increase the amount of the Commitment of any Lender hereunder, or permit the Borrower to assign its rights or obligations under this Agreement.

8.2.4 Amend this Section 8.2.

No amendment of any provision of this Agreement relating to the Agent shall be effective without the written consent of the Agent. The Agent may waive payment of the fee required under Section 12.3.2 without obtaining the consent of any other party to this Agreement.

8.3. Preservation of Rights. No delay or omission of the Lenders or the Agent to exercise any right under the Loan Documents shall impair such right or be construed to be a waiver of any Default or an acquiescence therein, and the making of a Loan notwithstanding the existence of a Default or the inability of the Borrower to satisfy the conditions precedent to such Loan shall not constitute any waiver or acquiescence. Any single or partial exercise of any such right shall not preclude other or further exercise thereof or the exercise of any other right, and no waiver, amendment or other variation of the terms, conditions or provisions of the Loan Documents whatsoever shall be valid unless in writing signed by the Lenders required pursuant to Section 8.2, and then only to the extent in such writing specifically set forth. All remedies contained in the Loan Documents or by law afforded shall be cumulative and all shall be available to the Agent and the Lenders until the Obligations have been paid in full.

ARTICLE IX

GENERAL PROVISIONS

9.1. Survival of Representations. All representations and warranties of the Borrower contained in this Agreement shall survive the making of the Loans herein contemplated.

9.2. Governmental Regulation. Anything contained in this Agreement to the contrary notwithstanding, no Lender shall be obligated to extend credit to the Borrower in violation of any limitation or prohibition provided by any applicable statute or regulation.

9.3. Headings. Section headings in the Loan Documents are for convenience of reference only, and shall not govern the interpretation of any of the provisions of the Loan Documents.

9.4. Entire Agreement. The Loan Documents embody the entire agreement and understanding among the Borrower, the Agent and the Lenders and supersede all prior agreements and understandings among the Borrower, the Agent and the Lenders relating to the subject matter thereof other than those contained in the fee letter described in Section 10.13 which shall survive and remain in full force and effect during the term of this Agreement.

9.5. Several Obligations; Benefits of this Agreement. The respective obligations of the Lenders hereunder are several and not joint and no Lender shall be the partner or agent of any other (except to the extent to which the Agent is authorized to act as such). The failure of any Lender to perform any of its obligations hereunder shall not relieve any other Lender from any of its obligations hereunder. This Agreement shall not be construed so as to confer any right or benefit upon any Person other than the parties to this Agreement and their respective successors and assigns, *provided, however,* that the parties hereto expressly agree that each Arranger shall enjoy the benefits of the provisions of Sections 9.6, 9.10 and 10.11 to the extent specifically set forth therein and shall have the right to enforce such provisions on its own behalf and in its own name to the same extent as if it were a party to this Agreement.

9.6. Expenses; Indemnification. (i) The Borrower shall reimburse the Agent and each Arranger for any costs, internal charges and out-of-pocket expenses (including attorneys' and paralegals' fees and time charges of attorneys for the Agent, which attorneys may be employees of the Agent and expenses of and fees for other advisors and professionals engaged by the Agent or any Arranger) paid or incurred by the Agent or any Arranger in connection with the investigation, preparation, negotiation, documentation, execution, delivery, syndication, distribution (including, without limitation, via the internet), review, amendment, modification and administration of the Loan Documents. The Borrower also agrees to reimburse the Agent, the Syndication Agent, the Co-Documentation Agents, the Arrangers and the Lenders for any costs, internal charges and out-of-pocket expenses (including attorneys' and paralegals' fees and time charges and expenses of attorneys and paralegals for the Agent, the Syndication Agent, the Co-Documentation Agents, the Arrangers and the Lenders, which attorneys and paralegals may

be employees of the Agent, the Syndication Agent, the Co-Documentation Agents, the Arrangers or the Lenders) paid or incurred by the Agent, the Syndication Agent, the Arrangers or any Lender in connection with the collection and enforcement of the Loan Documents.

(ii) The Borrower hereby further agrees to indemnify the Agent, the Syndication Agent, the Co-Documentation Agents, the Arrangers, each Lender, their respective affiliates, and each of their directors, officers and employees against all losses, claims, damages, penalties, judgments, liabilities and expenses (including, without limitation, all expenses of litigation or preparation therefor whether or not the Agent, the Syndication Agent, the Co-Documentation Agents, the Arrangers, any Lender or any affiliate is a party thereto, and all reasonable attorneys' and paralegals' fees, reasonable time charges and reasonable expenses of attorneys and paralegals of the party seeking indemnification, which attorneys and paralegals may or may not be employees of such party seeking indemnification) which any of them may pay or incur arising out of or relating to this Agreement, the other Loan Documents, the transactions contemplated hereby or the direct or indirect application or proposed application of the proceeds of any Loan hereunder except to the extent that they have resulted from the gross negligence or willful misconduct of the party seeking indemnification. The obligations of the Borrower under this Section 9.6 shall survive the termination of this Agreement.

9.7. Numbers of Documents. All statements, notices, closing documents, and requests hereunder shall be furnished to the Agent with sufficient counterparts so that the Agent may furnish one to each of the Lenders, to the extent that the Agent deems necessary.

9.8. Accounting. Except as provided to the contrary herein, all accounting terms used in the calculation of any financial covenant or test shall be interpreted and all accounting determinations hereunder in the calculation of any financial covenant or test shall be made in accordance with Agreement Accounting Principles. If any changes in generally accepted accounting principles are hereafter required or permitted and are adopted by the Borrower or any of its Subsidiaries with the agreement of its independent certified public accountants and such changes result in a change in the method of calculation of any of the financial covenants, tests, restrictions or standards herein or in the related definitions or terms used therein ("Accounting Changes"), the parties hereto agree, at the Borrower's request, to enter into negotiations, in good faith, in order to amend such provisions in a credit neutral manner so as to reflect equitably such changes with the desired result that the criteria for evaluating the Borrower's and its Subsidiaries' financial condition shall be the same after such changes as if such changes had not been made; *provided, however,* until such provisions are amended in a manner reasonably satisfactory to the Agent and the Required Lenders, no Accounting Change shall be given effect in such calculations. In the event such amendment is entered into, all references in this Agreement to Agreement Accounting Principles shall mean generally accepted accounting principles as of the date of such amendment. Notwithstanding the foregoing, all financial statements to be delivered by the Borrower pursuant to Section 6.1 shall be prepared in accordance with generally accepted accounting principles in effect at such time.

9.9. Severability of Provisions. Any provision in any Loan Document that is held to be inoperative, unenforceable, or invalid in any jurisdiction shall, as to that jurisdiction, be inoperative, unenforceable, or invalid without affecting the remaining provisions in that jurisdiction or the operation, enforceability, or validity of that provision in any other jurisdiction, and to this end the provisions of all Loan Documents are declared to be severable.

9.10. Nonliability of Lenders. The relationship between the Borrower on the one hand and the Lenders and the Agent on the other hand shall be solely that of borrower and lender. Neither the Agent, nor any Arranger or Lender shall have any fiduciary responsibilities to the Borrower. Neither the Agent, nor any Arranger or Lender undertakes any responsibility to the Borrower to review or inform the Borrower of any matter in connection with any phase of the Borrower's business or operations. The Borrower agrees that neither the Agent, nor any Arranger or Lender shall have liability to the Borrower (whether sounding in tort, contract or otherwise) for losses suffered by the Borrower in connection with, arising out of, or in any way related to, the transactions contemplated and the relationship established by the Loan Documents, or any act, omission or event occurring in connection therewith, unless it is determined in a final non-appealable judgment by a court of competent jurisdiction that such losses resulted from the gross negligence or willful misconduct of the party from which recovery is sought. Neither the Agent, nor any Arranger or Lender shall have any liability with respect to, and the Borrower hereby waives, releases and agrees not to sue for, any special, indirect, consequential or punitive damages suffered by the Borrower in connection with, arising out of, or in any way related to the Loan Documents or the transactions contemplated thereby.

9.11. Confidentiality. Each Lender agrees to hold any confidential information which it may receive from the Borrower pursuant to this Agreement in confidence, except for disclosure (i) to its Affiliates and to other Lenders and their respective Affiliates, for use solely in connection with the transactions contemplated hereby, (ii) to legal counsel, accountants, and other professional advisors to such Lender or to a Transferee, in each case which have been informed as to the confidential nature of such information, (iii) to regulatory officials having jurisdiction over it, (iv) to any Person as required by law, regulation, or legal process, (v) to any Person in connection with any legal proceeding to which such Lender is a party, (vi) to such Lender's direct or indirect contractual counterparties in swap agreements or to legal counsel, accountants and other professional advisors to such counterparties, in each case which have been informed as to the confidential nature of such information, (vii) permitted by Section 12.4 and (viii) to rating agencies if requested or required by such agencies in connection with a rating relating to the Advances hereunder. Notwithstanding anything herein to the contrary, confidential information shall not include, and each Lender (and each employee, representative or other agent of any Lender) may disclose to any and all Persons, without limitation of any kind, the "tax treatment" and "tax structure" (in each case, within the meaning of Treasury Regulation Section 1.6011-4) of the transactions contemplated hereby and all materials of any kind (including opinions or other tax analyses) that are or have been provided to such Lender relating to such tax treatment or tax structure; *provided* that with respect to any document or similar item that in either case contains information concerning such tax treatment or tax structure of the transactions contemplated hereby as well as other information, this sentence shall only apply to such portions of the document or similar item that relate to such tax treatment or tax structure.

9.12. Lenders Not Utilizing Plan Assets. Each Lender and Designated Lender represents and warrants that none of the consideration used by such Lender or Designated Lender to make its Loans constitutes for any purpose of ERISA or Section 4975 of the Code assets of any "plan" as defined in Section 3(3) of ERISA or Section 4975 of the Code and the rights and interests of such Lender or Designated Lender in and under the Loan Documents shall not constitute such "plan assets" under ERISA.

9.13. Nonreliance. Each Lender hereby represents that it is not relying on or looking to any margin stock (as defined in Regulation U of the Board of Governors of the Federal Reserve System) for the repayment of the Loans provided for herein.

9.14. Disclosure. The Borrower and each Lender hereby acknowledge and agree that Bank One and/or its Affiliates from time to time may hold investments in, make other loans to or have other relationships with the Borrower and its Affiliates.

9.15. USA Patriot Act Notification. The following notification is provided to the Borrower pursuant to Section 326 of the USA Patriot Act of 2001, 31 U.S.C. Section 5318:

IMPORTANT INFORMATION ABOUT PROCEDURES FOR OPENING A NEW ACCOUNT. To help the government of the United States of America fight the funding of terrorism and money laundering activities, Federal law requires all financial institutions to obtain, verify, and record information that identifies each Person that opens an account, including any deposit account, treasury management account, loan, other extension of credit, or other financial services product. Accordingly, when the Borrower opens an account, the Agent and the Lenders will ask for the Borrower's name, tax identification number, business address, and other information that will allow the Agent and the Lenders to identify the Borrower. The Agent and the Lenders may also ask to see the Borrower's legal organizational documents or other identifying documents.

ARTICLE X

THE AGENT

10.1. Appointment; Nature of Relationship. Bank One, NA is hereby appointed by each of the Lenders as its contractual representative (herein referred to as the "Agent") hereunder and under each other Loan Document, and each of the Lenders irrevocably authorizes the Agent to act as the contractual representative of such Lender with the rights and duties expressly set forth herein and in the other Loan Documents. The Agent agrees to act as such contractual representative upon the express conditions contained in this Article X. Notwithstanding the use of the defined term "Agent," it is expressly understood and agreed that the Agent shall not have any fiduciary responsibilities to any Lender by reason of this Agreement or any other Loan Document and that the Agent is merely acting as the contractual representative of the Lenders with only those duties as are expressly set forth in this Agreement and the other Loan Documents. In its capacity as the Lenders' contractual representative, the Agent (i) does not hereby assume any fiduciary duties to any of the Lenders, (ii) is a "representative" of the Lenders within the meaning of the term "secured party" as defined in the Illinois Uniform Commercial Code and (iii) is acting as an independent contractor, the rights and duties of which are limited to

those expressly set forth in this Agreement and the other Loan Documents. Each of the Lenders hereby agrees to assert no claim against the Agent on any agency theory or any other theory of liability for breach of fiduciary duty, all of which claims each Lender hereby waives.

10.2. Powers. The Agent shall have and may exercise such powers under the Loan Documents as are specifically delegated to the Agent by the terms of each thereof, together with such powers as are reasonably incidental thereto. The Agent shall have no implied duties to the Lenders, or any obligation to the Lenders to take any action thereunder except any action specifically provided by the Loan Documents to be taken by the Agent.

10.3. General Immunity. Neither the Agent nor any of its directors, officers, agents or employees shall be liable to the Borrower, the Lenders or any Lender for any action taken or omitted to be taken by it or them hereunder or under any other Loan Document or in connection herewith or therewith except to the extent such action or inaction is determined in a final non-appealable judgment by a court of competent jurisdiction to have arisen from the gross negligence or willful misconduct of such Person.

10.4. No Responsibility for Loans, Recitals, etc. Neither the Agent nor any of its directors, officers, agents or employees shall be responsible for or have any duty to ascertain, inquire into, or verify (a) any statement, warranty or representation made in connection with any Loan Document or any borrowing hereunder; (b) the performance or observance of any of the covenants or agreements of any obligor under any Loan Document, including, without limitation, any agreement by an obligor to furnish information directly to each Lender; (c) the satisfaction of any condition specified in Article IV, except receipt of items required to be delivered solely to the Agent; (d) the existence or possible existence of any Default or Unmatured Default; (e) the validity, enforceability, effectiveness, sufficiency or genuineness of any Loan Document or any other instrument or writing furnished in connection therewith; (f) the value, sufficiency, creation, perfection or priority of any Lien in any collateral security; or (g) the financial condition of the Borrower or any guarantor of any of the Obligations or of any of the Borrower's or any such guarantor's respective Subsidiaries. The Agent shall have no duty to disclose to the Lenders information that is not required to be furnished by the Borrower to the Agent at such time, but is voluntarily furnished by the Borrower to the Agent (either in its capacity as Agent or in its individual capacity).

10.5. Action on Instructions of Lenders. The Agent shall in all cases be fully protected in acting, or in refraining from acting, hereunder and under any other Loan Document in accordance with written instructions signed by the Required Lenders, and such instructions and any action taken or failure to act pursuant thereto shall be binding on all of the Lenders. The Lenders hereby acknowledge that the Agent shall be under no duty to take any discretionary action permitted to be taken by it pursuant to the provisions of this Agreement or any other Loan Document unless it shall be requested in writing to do so by the Required Lenders. The Agent shall be fully justified in failing or refusing to take any action hereunder and under any other Loan Document unless it shall first be indemnified to its satisfaction by the Lenders pro rata against any and all liability, cost and expense that it may incur by reason of taking or continuing to take any such action.

10.6. Employment of Agents and Counsel. The Agent may execute any of its duties as Agent hereunder and under any other Loan Document by or through employees, agents, and attorneys-in-fact and shall not be answerable to the Lenders, except as to money or securities received by it or its authorized agents, for the default or misconduct of any such agents or attorneys-in-fact selected by it with reasonable care. The Agent shall be entitled to advice of counsel concerning the contractual arrangement between the Agent and the Lenders and all matters pertaining to the Agent's duties hereunder and under any other Loan Document.

10.7. Reliance on Documents; Counsel. The Agent shall be entitled to rely upon any Note, notice, consent, certificate, affidavit, letter, telegram, statement, paper or document believed by it to be genuine and correct and to have been signed or sent by the proper person or persons, and, in respect to legal matters, upon the opinion of counsel selected by the Agent, which counsel may be employees of the Agent.

10.8. Agent's Reimbursement and Indemnification. The Lenders agree to reimburse and indemnify the Agent, the Syndication Agent and the Co-Documentation Agents ratably in proportion to the Lenders' Pro Rata Shares of the Aggregate Commitment (or, if the Aggregate Commitment has been terminated, of the Outstanding Credit Exposure) (i) for any amounts not reimbursed by the Borrower for which the Agent, the Syndication Agent or either Co-Documentation Agent is entitled to reimbursement by the Borrower under the Loan Documents, (ii) for any other expenses incurred by the Agent, the Syndication Agent, or either Co-Documentation Agent on behalf of the Lenders, in connection with the preparation, execution, delivery, administration and enforcement of the Loan Documents (including, without limitation, for any expenses incurred by the Agent or the Syndication Agent in connection with any dispute between the Agent or the Syndication Agent and any Lender or between two or more of the Lenders) and (iii) for any liabilities, obligations, losses, damages, penalties, actions, judgments, suits, costs, expenses or disbursements of any kind and nature whatsoever which may be imposed on, incurred by or asserted against the Agent, the Syndication Agent, or either Co-Documentation Agent in any way relating to or arising out of the Loan Documents or any other document delivered in connection therewith or the transactions contemplated thereby (including, without limitation, for any such amounts incurred by or asserted against the Agent, the Syndication Agent, or either Co-Documentation Agent in connection with any dispute between the Agent, the Syndication Agent, the Co-Documentation Agents and any Lender or between two or more of the Lenders), or the enforcement of any of the terms of the Loan Documents or of any such other documents, *provided* that (i) no Lender shall be liable for any of the foregoing to the extent any of the foregoing is found in a final non-appealable judgment by a court of competent jurisdiction to have resulted from the gross negligence or willful misconduct of the party seeking indemnification and (ii) any indemnification required pursuant to Section 3.5(vii) shall, notwithstanding the provisions of this Section 10.8, be paid by the relevant Lender in accordance with the provisions thereof. The obligations of the Lenders under this Section 10.8 shall survive payment of the Obligations and termination of this Agreement.

10.9. Notice of Default. The Agent shall not be deemed to have knowledge or notice of the occurrence of any Default or Unmatured Default hereunder unless the Agent has received written notice from a Lender or the Borrower referring to this Agreement describing such Default or Unmatured Default and stating that such notice is a "notice of default". In the event that the Agent receives such a notice, the Agent shall give prompt notice thereof to the Lenders.

10.10. Rights as a Lender. In the event the Agent is a Lender, the Agent shall have the same rights and powers hereunder and under any other Loan Document with respect to its Commitment and its Loans as any Lender and may exercise the same as though it were not the Agent, and the term "Lender" or "Lenders" shall, at any time when the Agent is a Lender, unless the context otherwise indicates, include the Agent in its individual capacity. The Agent and its Affiliates may accept deposits from, lend money to, and generally engage in any kind of trust, debt, equity or other transaction, in addition to those contemplated by this Agreement or any other Loan Document, with the Borrower or any of its Subsidiaries in which the Borrower or such Subsidiary is not restricted hereby from engaging with any other Person. The Agent, in its individual capacity, is not obligated to remain a Lender.

10.11. Lender Credit Decision. Each Lender acknowledges that it has, independently and without reliance upon the Agent, any Arranger or any other Lender and based on the financial statements prepared by the Borrower and such other documents and information as it has deemed appropriate, made its own credit analysis and decision to enter into this Agreement and the other Loan Documents. Each Lender also acknowledges that it will, independently and without reliance upon the Agent, any Arranger or any other Lender and based on such documents and information as it shall deem appropriate at the time, continue to make its own credit decisions in taking or not taking action under this Agreement and the other Loan Documents.

10.12. Successor Agent. The Agent may resign at any time by giving written notice thereof to the Lenders and the Borrower, such resignation to be effective upon the appointment of a successor Agent or, if no successor Agent has been appointed, forty-five days after the retiring Agent gives notice of its intention to resign. The Agent may be removed at any time with or without cause by written notice received by the Agent from the Required Lenders, such removal to be effective on the date specified by the Required Lenders. Upon any such resignation or removal, the Required Lenders shall have the right to appoint, on behalf of the Borrower and the Lenders, a successor Agent. If no successor Agent shall have been so appointed by the Required Lenders within thirty days after the resigning Agent's giving notice of its intention to resign, then the resigning Agent may appoint, on behalf of the Borrower and the Lenders, a successor Agent. Notwithstanding the previous sentence, the Agent may at any time without the consent of the Borrower or any Lender, appoint any of its Affiliates which is a commercial bank as a successor Agent hereunder. If the Agent has resigned or been removed and no successor Agent has been appointed, the Lenders may perform all the duties of the Agent hereunder and the Borrower shall make all payments in respect of the Obligations to the applicable Lender and for all other purposes shall deal directly with the Lenders. No successor Agent shall be deemed to be appointed hereunder until such successor Agent has accepted the appointment. Any such successor Agent shall be a commercial bank having capital and retained earnings of at least $100,000,000. Upon the acceptance of any appointment as Agent hereunder by a successor Agent, such successor Agent shall thereupon succeed to and become vested with all the rights, powers, privileges and duties of the resigning or removed Agent. Upon the effectiveness of the resignation or removal of the Agent, the resigning or removed Agent shall be discharged from its duties and obligations hereunder and under the Loan Documents. After the effectiveness of the resignation or removal of an Agent, the provisions of this Article X shall continue in effect for the benefit of such Agent in respect of any actions taken or omitted to be taken by it while it was acting as the Agent hereunder and under the other Loan Documents. In the event that there is a successor to the Agent by merger, or the Agent assigns its duties and

obligations to an Affiliate pursuant to this Section 10.12, then the term "Prime Rate" as used in this Agreement shall mean the prime rate, base rate or other analogous rate of the new Agent.

10.13. Agent and Arrangers' Fees. The Borrower agrees to pay to the Agent and each Arranger, for their respective accounts, the fees agreed to by the Borrower, the Agent and such Arranger pursuant to those certain letter agreements dated November 3, 2003, or as otherwise agreed from time to time.

10.14. Delegation to Affiliates. The Borrower and the Lenders agree that the Agent may delegate any of its duties under this Agreement to any of its Affiliates. Any such Affiliate (and such Affiliate's directors, officers, agents and employees) which performs duties in connection with this Agreement shall be entitled to the same benefits of the indemnification, waiver and other protective provisions to which the Agent is entitled under Articles IX and X.

10.15. Syndication Agent and Co-Documentation Agents. None of the Syndication Agent and the Co-Documentation Agents shall have any obligation, liability, responsibility or duty under this Agreement other than those applicable to all Lenders. Without limiting the foregoing, none of the Syndication Agent and the Co-Documentation Agents shall have or be deemed to have a fiduciary relationship with any Lender. Each Lender hereby makes the same acknowledgements with respect to the Syndication Agent and the Co-Documentation Agents as it makes with respect to the Agent in Section 10.11.

ARTICLE XI

SETOFF; RATABLE PAYMENTS

11.1. Setoff. In addition to, and without limitation of, any rights of the Lenders under applicable law, if the Borrower becomes insolvent, however evidenced, or any Default occurs, any and all deposits (including all account balances, whether provisional or final and whether or not collected or available) and any other Indebtedness at any time held or owing by any Lender or any Affiliate of any Lender to or for the credit or account of the Borrower may be offset and applied toward the payment of the Obligations owing to such Lender, whether or not the Obligations, or any part thereof, shall then be due.

11.2. Ratable Payments. If any Lender, whether by setoff or otherwise, has payment made to it upon its Loans (other than payments received pursuant to Section 3.1, 3.2, 3.4 or 3.5) in a greater proportion than that received by any other Lender, such Lender agrees, promptly upon demand, to purchase a portion of the Loans held by the other Lenders so that after such purchase each Lender will hold its ratable proportion of Loans. If any Lender, whether in connection with setoff or amounts which might be subject to setoff or otherwise, receives collateral or other protection for its Obligations or such amounts which may be subject to setoff, such Lender agrees, promptly upon demand, to take such action necessary such that all Lenders share in the benefits of such collateral ratably in proportion to their Loans. In case any such payment is disturbed by legal process, or otherwise, appropriate further adjustments shall be made.

ARTICLE XII

BENEFIT OF AGREEMENT; ASSIGNMENTS; PARTICIPATIONS

12.1. Successors and Assigns; Designated Lenders.

12.1.1 Successors and Assigns. The terms and provisions of the Loan Documents shall be binding upon and inure to the benefit of the Borrower, the Agent and the Lenders and their respective successors and assigns permitted hereby, except that (i) the Borrower shall not have the right to assign its rights or obligations under the Loan Documents without the prior written consent of each Lender, (ii) any assignment by any Lender must be made in compliance with Section 12.3, and (iii) any transfer by participation must be made in compliance with Section 12.2. Any attempted assignment or transfer by any party not made in compliance with this Section 12.1 shall be null and void, unless such attempted assignment or transfer is treated as a participation in accordance with Section 12.3.3. The parties to this Agreement acknowledge that clause (ii) of this Section 12.1 relates only to absolute assignments and this Section 12.1 does not prohibit assignments creating security interests, including, without limitation, (x) any pledge or assignment by any Lender of all or any portion of its rights under this Agreement and any Note to a Federal Reserve Bank, (y) in the case of a Lender which is a Fund, any pledge or assignment of all or any portion of its rights under this Agreement and any Note to its trustee in support of its obligations to its trustee or (z) any pledge or assignment by any Lender of all or any portion of its rights under this Agreement and any Note to direct or indirect contractual counterparties in swap agreements relating to the Loans; *provided, however,* that no such pledge or assignment creating a security interest shall release the transferor Lender from its obligations hereunder unless and until the parties thereto have complied with the provisions of Section 12.3. The Agent may treat the Person which made any Loan or which holds any Note as the owner thereof for all purposes hereof unless and until such Person complies with Section 12.3; *provided, however,* that the Agent may in its discretion (but shall not be required to) follow instructions from the Person which made any Loan or which holds any Note to direct payments relating to such Loan or Note to another Person. Any assignee of the rights to any Loan or any Note agrees by acceptance of such assignment to be bound by all the terms and provisions of the Loan Documents. Any request, authority or consent of any Person, who at the time of making such request or giving such authority or consent is the owner of the rights to any Loan (whether or not a Note has been issued in evidence thereof), shall be conclusive and binding on any subsequent holder or assignee of the rights to such Loan.

12.1.2 Designated Lenders.

(i) Subject to the terms and conditions set forth in this Section 12.1.2, any Lender may from time to time elect to designate an Eligible Designee to provide all or any part of the Loans to be made by such Lender pursuant to this Agreement; provided that the designation of an Eligible Designee by any Lender for purposes of this Section 12.1.2 shall be subject to the approval of the Agent (which consent shall not be unreasonably withheld or delayed). Upon the execution by the parties

to each such designation of an agreement in the form of Exhibit F hereto (a “Designation Agreement”) and the acceptance thereof by the Agent, the Eligible Designee shall become a Designated Lender for purposes of this Agreement. The Designating Lender shall thereafter have the right to permit the Designated Lender to provide all or a portion of the Loans to be made by the Designating Lender pursuant to the terms of this Agreement and the making of the Loans or portion thereof shall satisfy the obligations of the Designating Lender to the same extent, and as if, such Loan was made by the Designating Lender. As to any Loan made by it, each Designated Lender shall have all the rights a Lender making such Loan would have under this Agreement and otherwise; provided, (x) that all voting rights under this Agreement shall be exercised solely by the Designating Lender, (y) each Designating Lender shall remain solely responsible to the other parties hereto for its obligations under this Agreement, including the obligations of a Lender in respect of Loans made by its Designated Lender and (z) no Designated Lender shall be entitled to reimbursement under Article III hereof for any amount which would exceed the amount that would have been payable by the Borrower to the Lender from which the Designated Lender obtained any interests hereunder. No additional Notes shall be required with respect to Loans provided by a Designated Lender; provided, however, to the extent any Designated Lender shall advance funds, the Designating Lender shall be deemed to hold the Notes in its possession as an agent for such Designated Lender to the extent of the Loan funded by such Designated Lender. Such Designating Lender shall act as administrative agent for its Designated Lender and give and receive notices and communications hereunder. Any payments for the account of any Designated Lender shall be paid to its Designating Lender as administrative agent for such Designated Lender and neither the Borrower nor the Agent shall be responsible for any Designating Lender’s application of such payments. In addition, any Designated Lender may (1) with notice to, but without the consent of the Borrower or the Agent, assign all or portions of its interests in any Loans to its Designating Lender or to any financial institution consented to by the Agent providing liquidity and/or credit facilities to or for the account of such Designated Lender and (2) subject to advising any such Person that such information is to be treated as confidential in accordance with Section 9.11, disclose on a confidential basis any non-public information relating to its Loans to any rating agency, commercial paper dealer or provider of any guarantee, surety or credit or liquidity enhancement to such Designated Lender.

(ii) Each party to this Agreement hereby agrees that it shall not institute against, or join any other Person in instituting against, any Designated Lender any bankruptcy, reorganization, arrangement, insolvency or liquidation proceeding or other proceedings under any federal or state bankruptcy or similar law for one year and a day after the payment in full of all outstanding senior indebtedness of any Designated Lender; provided that the Designating Lender for each Designated Lender hereby agrees to indemnify, save and hold harmless each other party hereto for any loss, cost, damage and expense arising out of its inability to institute any such proceeding against such Designated Lender. This Section 12.1.2(ii) shall survive the termination of this Agreement.

12.2. Participations.

12.2.1 Permitted Participants; Effect. Any Lender may, in the ordinary course of its business and in accordance with applicable law, at any time sell to one or more banks or other entities (“Participants”) participating interests in any Loan owing to such Lender, any Note held by such Lender, any Commitment of such Lender or any other interest of such Lender under the Loan Documents. In the event of any such sale by a Lender of participating interests to a Participant, such Lender’s obligations under the Loan Documents shall remain unchanged, such Lender shall remain solely responsible to the other parties hereto for the performance of such obligations, such Lender shall remain the owner of its Loans and the holder of any Note issued to it in evidence thereof for all purposes under the Loan Documents, all amounts payable by the Borrower under this Agreement shall be determined as if such Lender had not sold such participating interests, and the Borrower and the Agent shall continue to deal solely and directly with such Lender in connection with such Lender’s rights and obligations under the Loan Documents.

12.2.2 Voting Rights. Each Lender shall retain the sole right to approve, without the consent of any Participant, any amendment, modification or waiver of any provision of the Loan Documents other than any amendment, modification or waiver with respect to any Loan or Commitment in which such Participant has an interest which would require consent of all of the Lenders pursuant to the terms of Section 8.2.

12.2.3 Benefit of Certain Provisions. The Borrower agrees that each Participant shall be deemed to have the right of setoff provided in Section 11.1 in respect of its participating interest in amounts owing under the Loan Documents to the same extent as if the amount of its participating interest were owing directly to it as a Lender under the Loan Documents, *provided* that each Lender shall retain the right of setoff provided in Section 11.1 with respect to the amount of participating interests sold to each Participant. The Lenders agree to share with each Participant, and each Participant, by exercising the right of setoff provided in Section 11.1, agrees to share with each Lender, any amount received pursuant to the exercise of its right of setoff, such amounts to be shared in accordance with Section 11.2 as if each Participant were a Lender. The Borrower further agrees that each Participant shall be entitled to the benefits of Sections 3.1, 3.2, 3.4 and 3.5 to the same extent as if it were a Lender and had acquired its interest by assignment pursuant to Section 12.3, *provided* that (i) a Participant shall not be entitled to receive any greater payment under Section 3.1, 3.2, 3.4 or 3.5 than the Lender who sold the participating interest to such Participant would have received had it retained such interest for its own account, unless the sale of such interest to such Participant is made with the prior written consent of the Borrower, and (ii) any Participant not incorporated under the laws of the United States of America or any State thereof agrees to comply with the provisions of Section 3.5 to the same extent as if it were a Lender.

12.3. Assignments.

12.3.1 Permitted Assignments. Any Lender may at any time assign to one or more banks or other entities (“Purchasers”) all or any part of its rights and obligations

under the Loan Documents. Such assignment shall be substantially in the form of Exhibit C or in such other form as may be agreed to by the parties thereto. Each such assignment with respect to a Purchaser which is not a Lender or an Affiliate of a Lender or an Approved Fund shall either be in an amount equal to the entire applicable Commitment and Loans of the assigning Lender or (unless each of the Borrower and the Agent otherwise consents) be in an aggregate amount not less than $2,500,000. The amount of the assignment shall be based on the Commitment or outstanding Loans (if the Commitment has been terminated) subject to the assignment, determined as of the date of such assignment or as of the “Trade Date,” if the “Trade Date” is specified in the assignment.

12.3.2 Consents. The consent of the Borrower shall be required prior to an assignment becoming effective unless the Purchaser is a Lender, an Affiliate of a Lender or an Approved Fund, provided that the consent of the Borrower shall not be required if (i) a Default has occurred and is continuing or (ii) if such assignment is in connection with the physical settlement of any Lender’s obligations to direct or indirect contractual counterparties in swap agreements relating to the Loans; provided, that the assignment without the Borrower’s consent pursuant to clause (ii) shall not increase the Borrower’s liability under Section 3.5. The consent of the Agent shall be required prior to an assignment becoming effective unless the Purchaser is a Lender, an Affiliate of a Lender or an Approved Fund. Any consent required under this Section 12.3.2 shall not be unreasonably withheld or delayed.

12.3.3 Effect; Effective Date. Upon (i) delivery to the Agent of an assignment, together with any consents required by Sections 12.3.1 and 12.3.2, and (ii) payment of a $3,500 fee to the Agent for processing such assignment (unless such fee is waived by the Agent), such assignment shall become effective on the effective date specified in such assignment. The assignment shall contain a representation and warranty by the Purchaser to the effect that none of the funds, money, assets or other consideration used to make the purchase and assumption of the Commitment and Loans under the applicable assignment agreement constitutes “plan assets” as defined under ERISA and that the rights, benefits and interests of the Purchaser in and under the Loan Documents will not be “plan assets” under ERISA. On and after the effective date of such assignment, such Purchaser shall for all purposes be a Lender party to this Agreement and any other Loan Document executed by or on behalf of the Lenders and shall have all the rights, benefits and obligations of a Lender under the Loan Documents, to the same extent as if it were an original party thereto, and the transferor Lender shall be released with respect to the Commitment and Loans assigned to such Purchaser without any further consent or action by the Borrower, the Lenders or the Agent. In the case of an assignment covering all of the assigning Lender’s rights, benefits and obligations under this Agreement, such Lender shall cease to be a Lender hereunder but shall continue to be entitled to the benefits of, and subject to, those provisions of this Agreement and the other Loan Documents which survive payment of the Obligations and termination of the Loan Documents. Any assignment or transfer by a Lender of rights or obligations under this Agreement that does not comply with this Section 12.3 shall be treated for purposes of this Agreement as a sale by such Lender of a participation in such rights and obligations in accordance with Section 12.2. Upon the consummation of any assignment to a Purchaser pursuant to this

Section 12.3.3, the transferor Lender, the Agent and the Borrower shall, if the transferor Lender or the Purchaser desires that its Loans be evidenced by Notes, make appropriate arrangements so that, upon cancellation and surrender to the Borrower of the Notes (if any) held by the transferor Lender, new Notes or, as appropriate, replacement Notes are issued to such transferor Lender, if applicable, and new Notes or, as appropriate, replacement Notes, are issued to such Purchaser, in each case in principal amounts reflecting their respective Commitments, as adjusted pursuant to such assignment.

12.3.4 Register. The Agent, acting solely for this purpose as an agent of the Borrower (and the Borrower hereby designates the Agent to act in such capacity), shall maintain at one of its offices in Chicago, Illinois a copy of each Assignment and Assumption delivered to it and a register for the recordation of the names and addresses of the Lenders, and the Commitments of, and principal amounts of the Loans owing to, each Lender pursuant to the terms hereof from time to time (the "Register"). The entries in the Register shall be conclusive, absent manifest error, and the Borrower, the Agent and the Lenders may treat each Person whose name is recorded in the Register pursuant to the terms hereof as a Lender hereunder for all purposes of this Agreement, notwithstanding notice to the contrary. The Register shall be available for inspection by the Borrower and any Lender, at any reasonable time and from time to time upon reasonable prior notice.

12.4. Dissemination of Information. The Borrower authorizes each Lender to disclose to any Participant or Purchaser or any other Person acquiring an interest in the Loan Documents by operation of law (each a "Transferee") and any prospective Transferee any and all information in such Lender's possession concerning the creditworthiness of the Borrower and its Subsidiaries; *provided* that each Transferee and prospective Transferee agrees to be bound by Section 9.11 of this Agreement.

12.5. Tax Certifications. If any interest in any Loan Document is transferred to any Transferee which is not incorporated under the laws of the United States or any State thereof, the transferor Lender shall cause such Transferee, concurrently with the effectiveness of such transfer, to comply with the provisions of Section 3.5(iv).

ARTICLE XIII

NOTICES

13.1. Notices. Except as otherwise permitted by Section 2.14 with respect to borrowing notices, all notices, requests and other communications to any party hereunder shall be in writing (including electronic transmission, facsimile transmission or similar writing) and shall be given to such party: (x) in the case of the Borrower, the Lenders or the Agent, at its address or facsimile number set forth on the signature pages hereof or, (y) in the case of any party, at such other address or facsimile number as such party may hereafter specify for the purpose by notice to the Agent and the Borrower in accordance with the provisions of this Section 13.1. Each such notice, request or other communication shall be effective (i) if given by facsimile transmission, when transmitted to the facsimile number specified in this Section and confirmation of receipt is received, (ii) if given by mail, 72 hours after such communication is deposited in the mails with

first class postage prepaid, addressed as aforesaid, or (iii) if given by any other means, when delivered (or, in the case of electronic transmission, received) at the address specified in this Section; *provided* that notices to the Agent under Article II shall not be effective until received.

13.2. Change of Address. The Borrower, the Agent and any Lender may each change the address for service of notice upon it by a notice in writing to the other parties hereto.

ARTICLE XIV

COUNTERPARTS

This Agreement may be executed in any number of counterparts, all of which taken together shall constitute one agreement, and any of the parties hereto may execute this Agreement by signing any such counterpart. This Agreement shall be effective when it has been executed by the Borrower, the Agent and the Lenders and each party has notified the Agent by facsimile transmission or telephone that it has taken such action. Delivery of an executed counterpart of a signature page of this Agreement by telecopy shall be effective as delivery of a manually executed original counterpart of this Agreement.

ARTICLE XV

CHOICE OF LAW; CONSENT TO JURISDICTION; WAIVER OF JURY TRIAL

15.1 CHOICE OF LAW. THE LOAN DOCUMENTS (OTHER THAN THOSE CONTAINING A CONTRARY EXPRESS CHOICE OF LAW PROVISION) SHALL BE GOVERNED BY AND CONSTRUED IN ACCORDANCE WITH THE INTERNAL LAWS (INCLUDING, WITHOUT LIMITATION, 735 ILCS SECTION 105/5-1 ET SEQ, BUT OTHERWISE WITHOUT REGARD TO THE CONFLICT OF LAWS PROVISIONS) OF THE STATE OF ILLINOIS, BUT GIVING EFFECT TO FEDERAL LAWS APPLICABLE TO NATIONAL BANKS.

15.2 CONSENT TO JURISDICTION. THE BORROWER, THE AGENT AND EACH LENDER HEREBY IRREVOCABLY SUBMITS TO THE NON-EXCLUSIVE JURISDICTION OF ANY UNITED STATES FEDERAL OR ILLINOIS STATE COURT SITTING IN CHICAGO, ILLINOIS IN ANY ACTION OR PROCEEDING ARISING OUT OF OR RELATING TO ANY LOAN DOCUMENTS AND THE BORROWER, THE AGENT AND EACH LENDER HEREBY IRREVOCABLY AGREES THAT ALL CLAIMS IN RESPECT OF SUCH ACTION OR PROCEEDING MAY BE HEARD AND DETERMINED IN ANY SUCH COURT AND IRREVOCABLY WAIVES ANY OBJECTION IT MAY NOW OR HEREAFTER HAVE AS TO THE VENUE OF ANY SUCH SUIT, ACTION OR PROCEEDING BROUGHT IN SUCH A COURT OR THAT SUCH COURT IS AN INCONVENIENT FORUM. NOTHING HEREIN SHALL LIMIT THE RIGHT OF THE AGENT OR ANY LENDER TO BRING PROCEEDINGS AGAINST THE BORROWER IN THE COURTS OF ANY OTHER JURISDICTION. ANY JUDICIAL PROCEEDING BY THE BORROWER AGAINST THE AGENT OR ANY LENDER INVOLVING, DIRECTLY OR INDIRECTLY, ANY MATTER IN ANY

WAY ARISING OUT OF, RELATED TO, OR CONNECTED WITH ANY LOAN DOCUMENT SHALL BE BROUGHT ONLY IN A COURT IN CHICAGO, ILLINOIS.

15.3 WAIVER OF JURY TRIAL. THE BORROWER, THE AGENT AND EACH LENDER HEREBY WAIVE TRIAL BY JURY IN ANY JUDICIAL PROCEEDING INVOLVING, DIRECTLY OR INDIRECTLY, ANY MATTER (WHETHER SOUNDING IN TORT, CONTRACT OR OTHERWISE) IN ANY WAY ARISING OUT OF, RELATED TO, OR CONNECTED WITH ANY LOAN DOCUMENT OR THE RELATIONSHIP ESTABLISHED THEREUNDER.

[Signature Pages Follow]

IN WITNESS WHEREOF, the Borrower, the Lenders and the Agent have executed this Agreement as of the date first above written.

OGE ENERGY CORP.

By: /s/ James R. Hatfield

Title: Senior Vice President and Chief Financial Officer

321 N. Harvey
Oklahoma City, OK 73102

Attention: James R. Hatfield

Telephone: (405) 553-3984
FAX: (405) 553-3760

BANK ONE, NA,
Individually and as Agent

By: /s/ Jane Bek Keil

Title: Director

1 Bank One Plaza
Chicago, Illinois 60670

Attention: Teresita Siao

Telephone: ( )
FAX: ( )

WACHOVIA BANK, NATIONAL ASSOCIATION, Individually and as Syndication Agent

By: /s/ Lawrence P. Sullivan

Title: Vice President

301 S. College Street, DC-05
Charlotte, NC 28288-0760

Attention: Lawrence P. Sullivan

Telephone: (704) 715-1794
FAX: (704) 383-6647

COMMERZBANK, AG,
Individually and as
Co-Documentation Agent

By: /s/ Harry P. Yergey

Title: Senior Vice President & Manager

By: /s/ Subash R. Viswanathan

Title: Senior Vice President

Attention:

Telephone: (   )
FAX: (   )

CITIBANK, N.A.,
Individually and as
Co-Documentation Agent

By: /s/ Robert J. Harrity, Jr.

Title: Managing Director

388 Greenwich / 21st Floor
New York, NY 10013

Attention:

Telephone: (212) 816-8554
FAX: (   )

THE BANK OF NEW YORK,
Individually and as
Co-Documentation Agent

By: /s/ Nathan S. Howard

Title: Vice President

One Wall Street, 19th Floor
New York, NY 10286

Attention: Nathan S. Howard

Telephone: (212) 635-7916
FAX: (212) 635-7923

THE ROYAL BANK OF SCOTLAND plc,
Individually and as
Senior Managing Agent

By: /s/ Patricia Dundee

Title: Senior Vice President

Attention:

Telephone: (713) 221-2423
FAX: (713) 221-2430

KEYBANK NATIONAL ASSOCIATION,
Individually and as
Senior Managing Agent

By: /s/ Kevin D. Smith

Title: Vice President

Attention: Carolyn Zielski

Telephone: (216) 689-0413
FAX: (216) 689-4981

BANK OF OKLAHOMA N.A.,
as a Lender

By: /s/ Laura Christofferson

Title: Senior Vice President

Attention: Laura Christofferson

Telephone: (405) 272-2327
FAX: (405) 272-2588

UMB BANK, n.a.,
as a Lender

By: /s/ Richard J. Lehrter

Title: Community Bank President

Attention: Richard J. Lehrter

Telephone: (918) 295-2000
FAX: (918) 295-2020

UNION BANK OF CALIFORNIA, N.A.,
as a Lender

By: /s/ Susan K. Johnson

Title: Vice President

445 South Figueroa Street, 15th Fl.

Los Angeles, CA 90071

Attention: Susan K. Johnson

Telephone: (213) 236-4125
FAX: (213) 236-4096

UBS LOAN FINANCE LLC,
as a Lender

By: /s/ Barbara Ezell - McMichael

Title: Associate Director

Banking Products Services US

By: /s/ Joselin Fernandes

Title: Associate Director

Banking Products Services US

Attention: Christopher Aitkin

Telephone: (203) 719-3845
FAX: (203) 719-3888

LANDESBANK BADEN-
WUERTTENBERG,
as a Lender

By: /s/ Karen Richard

Title: Vice President

Attention: Corporate Desk

Telephone: (212) 584-1750
FAX: (212) 584-1759

SUMITOMO MITSUI BANKING
CORPORATION,
as a Lender

By: /s/ William M. Ginn

Title: General Manager

Attention:

Telephone: ( )
FAX: ( )

LASALLE BANK, NATIONAL
ASSOCIATION,
as a Lender

By: /s/ Meghan C. Payne

Title: First Vice President

Attention: Meghan C. Payne

Telephone: (312) 904-2509
FAX: (312) 904-1994

JPMORGAN CHASE BANK,
as a Lender

By: /s/ Thomas T. Hou

Title: Vice President

Attention: Thomas T. Hou

Telephone: (212) 270-6072
FAX: (212) 270-3897

COBANK, ACB,
as a Lender

By: /s/ Cathleen D. Reed

Title: Assistant Vice President

Attention: Deann Sullivan

Telephone: (303) 740-4315
FAX: (303) 740-4011

BANK HAPOALIM B.M.,
as a Lender

By: /s/ Laura Raffa

Title: Senior Vice President

Attention: Michael Byrne

Telephone (312) 228-6410
FAX: (312) 228-6490

COMMITMENT SCHEDULE

LENDER		**COMMITMENT**
Bank One, NA	$	27,500,000
Wachovia Bank, National Association	$	27,500,000
Commerzbank AG	$	27,500,000
Citibank, N.A	$	20,000,000
The Bank of New York	$	20,000,000
The Royal Bank of Scotland plc	$	20,000,000
KeyBank National Association	$	20,000,000
Bank of Oklahoma N.A	$	17,500,000
UMB Bank, n.a	$	15,000,000
Union Bank of California, N.A	$	15,000,000
UBS Loan Finance LLC	$	15,000,000
Landesbank Baden-Wuerttenberg	$	15,000,000
Sumitomo Mitsui Banking Corporation	$	15,000,000
LaSalle Bank, National Association	$	12,500,000
JPMorgan Chase Bank	$	12,500,000
CoBank, ACB	$	12,500,000
Bank Hapoalim B.M	$	7,500,000
AGGREGATE COMMITMENT	$	300,000,000

PRICING SCHEDULE

APPLICABLE MARGIN AND TERM LOAN MARGIN	**LEVEL I STATUS**	**LEVEL II STATUS**	**LEVEL III STATUS**	**LEVEL IV STATUS**	**LEVEL V STATUS**	**LEVEL VI STATUS**
Eurodollar Rate	*0.525%*	*0.625%*	*0.725%*	*0.90%*	*1.20%*	*1.60%*
Floating Rate	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*

Term Loan Margin	*0.375%*	*0.375%*	*0.375%*	*0.375%*	*0.50*	*0.50*

APPLICABLE FEE RATE	**LEVEL I STATUS**	**LEVEL II STATUS**	**LEVEL III STATUS**	**LEVEL IV STATUS**	**LEVEL V STATUS**	**LEVEL VI STATUS**
Facility Fee	*0.10%*	*0.125%*	*0.15%*	*0.225%*	*0.30%*	*0.40%*
Utilization Fee (when usage exceeds 33 1/3%)	*0.125%*	*0.125%*	*0.125%*	*0.125%*	*0.25%*	*0.25%*

For the purposes of this Schedule, the following terms have the following meanings, subject to the final paragraph of this Schedule:

"Level I Status" exists at any date if, on such date, the Borrower's Moody's Rating is A2 or better or the Borrower's S&P Rating is A or better.

"Level II Status" exists at any date if, on such date, (i) the Borrower has not qualified for Level I Status and (ii) the Borrower's Moody's Rating is A3 or better or the Borrower's S&P Rating is A- or better.

"Level III Status" exists at any date if, on such date, (i) the Borrower has not qualified for Level I Status or Level II Status and (ii) the Borrower's Moody's Rating is Baa1 or better or the Borrower's S&P Rating is BBB+ or better.

"Level IV Status" exists at any date if, on such date, (i) the Borrower has not qualified for Level I Status, Level II Status or Level III Status and (ii) the Borrower's Moody's Rating is Baa2 or better or the Borrower's S&P Rating is BBB or better.

"Level V Status" exists at any date if, on such date, (i) the Borrower has not qualified for Level I Status, Level II Status, Level III Status or Level IV Status and (ii) the Borrower's Moody's Rating is Baa3 or better or the Borrower's S&P Rating is BBB- or better.

"Level VI Status" exists at any date if, on such date, the Borrower has not qualified for Level I Status, Level II Status, Level III Status, Level IV Status or Level V Status.

"Moody's Rating" means, at any time, the rating issued by Moody's and then in effect with respect to the Borrower's senior unsecured long-term debt securities without third-party credit enhancement.

"S&P Rating" means, at any time, the rating issued by S&P and then in effect with respect to the Borrower's senior unsecured long-term debt securities without third-party credit enhancement.

"Status" means either Level I Status, Level II Status, Level III Status, Level IV Status, Level V Status or Level VI Status.

The Applicable Margin, Term Loan Margin and Applicable Fee Rate shall be determined in accordance with the foregoing table based on the Borrower's Status as determined from its then-current Moody's and S&P Ratings. The credit rating in effect on any date for the purposes of this Schedule is that in effect at the close of business on such date. If at any time the Borrower has no Moody's Rating or no S&P Rating, Level VI Status shall exist.

If the Borrower is split-rated and the ratings differential is one level, the higher rating will apply. If the Borrower is split-rated and the ratings differential is two levels or more, the intermediate rating at the midpoint will apply. If there is no midpoint, the higher of the two intermediate ratings will apply.

SCHEDULE 1

SUBSIDIARIES
(See Section 5.8)

Name of Subsidiary	Jurisdiction of Organization	Percentage of Ownership	Owner
Oklahoma Gas and Electric Company (OG&E)*	Oklahoma	100.0	OGE Energy Corp.
OGE Consumer Loan LLC	Delaware	100.0	OG&E
OGE Consumer Loan II LLC	Delaware	100.0	OG&E
OGE Consumer Loan 2002, LLC	Delaware	100.0	OG&E
OGE Energy Capital Trust I*	Oklahoma	100.0	OGE Energy Corp.
Enogex Inc.*	Oklahoma	100.0	
	Oklahoma	100.0	OGE Energy

Enogex Products Corporation (EPC)*	Oklahoma	100.0	Corp.
OGE Energy Resources Inc.*	Oklahoma	100.0	Enogex Inc.
Enogex Exploration Corporation*	Oklahoma	100.0	Enogex Inc.
Enogex Gas Gathering, L.L.C.*	Oklahoma	100.0	Enogex Inc.
Enogex Arkansas Pipeline Corporation (EAPC)*			Enogex Inc.
NOARK-Pipeline System, Limited Partnership (NOARK)*	Arkansas	75.0	Enogex Inc. EAPC
NOARK Energy Services, L.L.C.	Oklahoma	100.0	NOARK
Ozark Gas Gathering, L.L.C.*	Oklahoma	100.0	NOARK
Ozark Gas Transmission, L.L.C.*	Oklahoma	100.0	NOARK
NOARK Pipeline Finance, L.L.C.*	Oklahoma	100.0	NOARK
Ozark Arkansas Gas Gathering, LLC	Arkansas	100.0	NOARK

Name of Subsidiary	Jurisdiction of Organization	Percentage of Ownership	Owner
Origen, Inc.	Oklahoma	100.00	OGE Energy Corp.

*Designates Material Sunsidiaries

SCHEDULE 2

ASSET DISPOSITIONS
(See Section 5.14)

None.

SCHEDULE 3

LIENS
(See Section 6.12)

None.

EXHIBIT A

FORM OF OPINIONS

[Omitted]

EXHIBIT B

COMPLIANCE CERTIFICATE

To: The Lenders parties to the
Credit Agreement Described Below

This Compliance Certificate is furnished pursuant to that certain Credit Agreement dated as of December 11, 2003 (as amended, modified, renewed or extended from time to time, the "Agreement") among OGE ENERGY CORP. (the "Borrower"), the lenders party thereto and Bank One, NA, as Agent for the

Lenders. Unless otherwise defined herein, capitalized terms used in this Compliance Certificate have the meanings ascribed thereto in the Agreement.

THE UNDERSIGNED HEREBY CERTIFIES THAT:

1. I am the duly elected ___________ of the Borrower;

2. I have reviewed the terms of the Agreement and I have made, or have caused to be made under my supervision, a detailed review of the transactions and conditions of the Borrower and its Subsidiaries during the accounting period covered by the attached financial statements;

3. The examinations described in paragraph 2 did not disclose, and I have no knowledge of, the existence of any condition or event which constitutes a Default or Unmatured Default during or at the end of the accounting period covered by the attached financial statements or as of the date of this Certificate, except as set forth below; and

4. Schedule I attached hereto sets forth financial data and computations evidencing the Borrower's compliance with certain covenants of the Agreement.

Described below are the exceptions, if any, to paragraph 3 by listing, in detail, the nature of the condition or event, the period during which it has existed and the action which the Borrower has taken, is taking, or proposes to take with respect to each such condition or event:

The foregoing certifications, together with the computations set forth in Schedule I hereto and the financial statements delivered with this Certificate in support hereof, are made and delivered this ___ day of ___________, ______.

____

SCHEDULE I TO COMPLIANCE CERTIFICATE

Compliance as of __________, _____ with
Provisions of Sections 6.15 and 6.16 of
the Agreement

EXHIBIT C

ASSIGNMENT AND ASSUMPTION AGREEMENT

This Assignment and Assumption (the "Assignment and Assumption") is dated as of the Effective Date set forth below and is entered into by and between [*Insert name of Assignor*] (the "Assignor") and [*Insert name of Assignee*] (the "Assignee"). Capitalized terms used but not defined herein shall have the meanings given to them in the Credit Agreement identified below (as amended, the "Credit Agreement"), receipt of a copy of which is hereby acknowledged by the Assignee. The Terms and Conditions set forth in Annex 1 attached hereto are hereby agreed to and incorporated herein by reference and made a part of this Assignment and Assumption as if set forth herein in full.

For an agreed consideration, the Assignor hereby irrevocably sells and assigns to the Assignee, and the Assignee hereby irrevocably purchases and assumes from the Assignor, subject to and in accordance with the Terms and Conditions and the Credit Agreement, as of the Effective Date inserted by the Agent as contemplated below, the interest in and to all of the Assignor's rights and obligations in its capacity as a Lender under the Credit Agreement and any other documents or instruments delivered pursuant thereto that represents the amount and percentage interest identified below of all of the Assignor's outstanding rights and obligations under the respective facilities identified below (including without limitation any letters of credit, guaranties and swingline loans included in such facilities and, to the extent permitted to be assigned under applicable law, all claims (including without limitation contract claims, tort claims, malpractice claims, statutory claims and all other claims at law or in equity), suits, causes of action and any other right of the Assignor against any Person whether known or unknown arising under or in connection with the Credit Agreement, any other documents or instruments delivered pursuant thereto or the loan transactions governed thereby) (the "Assigned Interest"). Such sale and assignment is without recourse to the Assignor and, except as expressly provided in this Assignment and Assumption, without representation or warranty by the Assignor.

1. Assignor: ______________________________

2. Assignee: ______________________________ [and is an Affiliate/Approved

Fund of [identify Lender]1

3. Borrower: OGE ENERGY CORP.

4. Agent: Bank One, NA, as the agent under the Credit Agreement.

5. Credit Agreement: The Credit Agreement dated as of December 11, 2003 among OGE ENERGY CORP., the Lenders party thereto, Bank One, NA, as Agent, and the other agents party thereto.

6. Assigned Interest:

	Aggregate Amount of Commitment/Loans for all Lenders*	Amount of Commitment/Loans Assigned*	Percentage Assigned of Commitment/Loans2
	$	$	_______%
	$	$	_______%
	$	$	_______%

7. Trade Date: ______________________________ 3

Effective Date: _____________, 20__ [TO BE INSERTED BY AGENT AND WHICH SHALL BE THE EFFECTIVE DATE OF RECORDATION OF TRANSFER BY THE AGENT.]

[1] Select as applicable.

* Amount to be adjusted by the counterparties to take into account any payments or prepayments made between the Trade Date and the Effective Date.

[2] Set forth, to at least 9 decimals, as a percentage of the Commitment/Loans of all Lenders thereunder.

[3] Insert if satisfaction of minimum amounts is to be determined as of the Trade Date.

The terms set forth in this Assignment and Assumption are hereby agreed to:

ASSIGNOR
[NAME OF ASSIGNOR]

By:____
Title:

ASSIGNEE
[NAME OF ASSIGNEE]

By:____
Title:

[Consented to and][4] Accepted:

BANK ONE, NA, as Agent

By:
Title:

[Consented to:][5]

OGE ENERGY CORP.

By:
Title:

---

[4] To be added only if the consent of the Agent is required by the terms of the Credit Agreement.

[5] To be added only if the consent of the Borrower is required by the terms of the Credit Agreement.

ANNEX 1
TERMS AND CONDITIONS FOR
ASSIGNMENT AND ASSUMPTION

1. Representations and Warranties.

1.1 Assignor. The Assignor represents and warrants that (i) it is the legal and beneficial owner of the Assigned Interest, (ii) the Assigned Interest is free and clear of any lien, encumbrance or other adverse claim and (iii) it has full power and authority, and has taken all action necessary, to execute and deliver this Assignment and Assumption and to consummate the transactions contemplated hereby. Neither the Assignor nor any of its officers, directors, employees, agents or attorneys shall be responsible for (i) any statements, warranties or representations made in or in connection with the Credit Agreement or any other Loan Document, (ii) the execution, legality, validity, enforceability, genuineness, sufficiency, perfection, priority, collectibility, or value of the Loan Documents or any collateral thereunder, (iii) the financial condition of the Borrower, any of its Subsidiaries or Affiliates or any other Person obligated in respect of any Loan Document, (iv) the performance or observance by the Borrower, any of its Subsidiaries or Affiliates or any other Person of any of their respective obligations under any Loan Document, (v) inspecting any of the property, books or records of the Borrower, or any guarantor, or (vi) any mistake, error of judgment, or action taken or omitted to be taken in connection with the Loans or the Loan Documents.

1.2. Assignee. The Assignee (a) represents and warrants that (i) it has full power and authority, and has taken all action necessary, to execute and deliver this Assignment and Assumption and to consummate the transactions contemplated hereby and to become a Lender under the Credit Agreement, (ii) from and after the Effective Date, it shall be bound by the provisions of the Credit Agreement as a Lender thereunder and, to the extent of the Assigned Interest, shall have the obligations of a Lender thereunder, (iii) agrees that its payment instructions and notice instructions are as set forth in Schedule 1 to this Assignment and Assumption, (iv) none of the funds, monies, assets or other consideration being used to make the purchase and assumption hereunder are “plan assets” as defined under ERISA and that its rights, benefits and interests in and under the Loan Documents will not be “plan assets” under ERISA, (v) agrees to indemnify and hold the Assignor harmless against all losses, costs and expenses (including, without limitation, reasonable attorneys’ fees) and liabilities incurred by the Assignor in connection with or arising in any manner from the Assignee’s non-performance of the obligations assumed under this Assignment and Assumption, (vi) it has received a copy of the Credit Agreement, together with copies of financial statements and such other documents and information as it has deemed appropriate to make its own credit analysis and decision to enter into this Assignment and Assumption and to purchase the Assigned Interest on the basis of which it has made such analysis and decision independently and without reliance on the Agent or any other Lender, and (vii) attached as Schedule 1 to this Assignment and Assumption is any documentation required to be delivered by the Assignee with respect to its tax status pursuant to the terms of the Credit Agreement, duly completed and executed by the Assignee and (b) agrees that (i) it will, independently and without reliance on the Agent, the Assignor or any other Lender,

and based on such documents and information as it shall deem appropriate at the time, continue to make its own credit decisions in taking or not taking action under the Loan Documents, and (ii) it will perform in accordance with their terms all of the obligations which by the terms of the Loan Documents are required to be performed by it as a Lender.

2. Payments. The Assignee shall pay the Assignor, on the Effective Date, the amount agreed to by the Assignor and the Assignee. From and after the Effective Date, the Agent shall make all payments in respect of the Assigned Interest (including payments of principal, interest, fees and other amounts) to the [Assignor][6] for amounts which have accrued to but excluding the Effective Date and to the Assignee for amounts which have accrued from and after the Effective Date.

3. General Provisions. This Assignment and Assumption shall be binding upon, and inure to the benefit of, the parties hereto and their respective successors and assigns. This Assignment and Assumption may be executed in any number of counterparts, which together shall constitute one instrument. Delivery of an executed counterpart of a signature page of this Assignment and Assumption by telecopy shall be effective as delivery of a manually executed counterpart of this Assignment and Assumption. This Assignment and Assumption shall be governed by, and construed in accordance with, the law of the State of Illinois.

6 If assignment is made pursuant to Section 2.19 and Borrower has made the payments required by said Section, the Assignor's portion of payments in respect of the Assigned Interest shall be payable to the Borrower.

ADMINISTRATIVE QUESTIONNAIRE

(Schedule to be supplied by Closing Unit or Trading Documentation Unit)

US AND NON-US TAX INFORMATION REPORTING REQUIREMENTS

(Schedule to be supplied by Closing Unit or Trading Documentation Unit)

EXHIBIT D

LOAN/CREDIT RELATED MONEY TRANSFER INSTRUCTION

To Bank One, NA,
as Agent (the "Agent") under the Credit Agreement
Described Below.

Re: Credit Agreement, dated December 11, 2003 (as the same may be amended or modified, the "Credit Agreement"), among OGE ENERGY CORP. (the "Borrower"), the Lenders named therein and the Agent. Capitalized terms used herein and not otherwise defined herein shall have the meanings assigned thereto in the Credit Agreement.

The Agent is specifically authorized and directed to act upon the following standing money transfer instructions with respect to the proceeds of Advances or other extensions of credit from time to time until receipt by the Agent of a specific written revocation of such instructions by the Borrower, *provided*, *however*, that the Agent may otherwise transfer funds as hereafter directed in writing by the Borrower in accordance with Section 13.1 of the Credit Agreement or based on any telephonic notice made in accordance with Section 2.14 of the Credit Agreement.

Facility Identification Number(s)____

Customer/Account Name ____

Transfer Funds To ____

____

For Account No. ____

Reference/Attention To ____

Authorized Officer (Customer Representative; Date ____________________

______________________________ ______________________________
(Please Print) Signature

Bank Officer Name Date ____________________

______________________________ ______________________________
(Please Print) Signature

(Deliver Completed Form to Credit Support Staff For Immediate Processing)

EXHIBIT E

NOTE

[Date]

OGE ENERGY CORP., an Oklahoma corporation (the "Borrower"), promises to pay to ____________________ (the "Lender") on the Facility Termination Date __________ DOLLARS ($_____) or, if less, the aggregate unpaid principal amount of all Loans made by the Lender to the Borrower pursuant to Article II of the Agreement (as hereinafter defined), in immediately available funds at the main office of Bank One, NA in Chicago, Illinois, as Agent, together with accrued but unpaid interest thereon. The Borrower shall pay interest on the unpaid principal amount hereof at the rates and on the dates set forth in the Agreement.

The Lender shall, and is hereby authorized to, record on the schedule attached hereto, or to otherwise record in accordance with its usual practice, the date and amount of each Loan and the date and amount of each principal payment hereunder.

This Note is one of the Notes issued pursuant to, and is entitled to the benefits of, the Credit Agreement dated as of December 11, 2003 (which, as it may be amended or modified and in effect from time to time, is herein called the "Agreement"), among the Borrower, the lenders party thereto, including the Lender, and Bank One, NA, as Agent, to which Agreement reference is hereby made for a statement of the terms and conditions governing this Note, including the terms and conditions under which this Note may be prepaid or its maturity date accelerated. Capitalized terms used herein and not otherwise defined herein are used with the meanings attributed to them in the Agreement.

Any assignment of this Note, or any rights or interest herein, may only be made in accordance with the terms and conditions of the Agreement. This Note is a registered Note and, as provided in the Agreement, the Borrower, the Agent and the Lenders may treat the person whose name is recorded in the Register as the owner hereof for all purposes, notwithstanding notice to the contrary. The entries in the Register shall be conclusive, absent manifest error.

OGE ENERGY CORP.

By: ____

Print Name: ____

Title: ____

SCHEDULE OF LOANS AND PAYMENTS OF PRINCIPAL
TO
NOTE OF OGE ENERGY CORP.,
DATED _____________, ____

Date	Principal Amount of Loan	Maturity of Interest Period	Principal Amount Paid	Unpaid Balance

EXHIBIT F

FORM OF DESIGNATION AGREEMENT

Dated ____________, 20__

Reference is made to the Credit Agreement dated as of December 11, 2003 (as amended or otherwise modified from time to time, the "Credit Agreement") among OGE ENERGY CORP., an Oklahoma corporation (the "Borrower"), the lenders from time to time party thereto (the "Lenders") and Bank One, NA (having its principal office in Chicago, IL), as Agent. Terms defined in the Credit Agreement are used herein as therein defined.

_________ (the "Designating Lender"), ____________ (the "Designated Lender"), and the Borrower agree as follows:

1. The Designating Lender hereby designates the Designated Lender, and the Designated Lender hereby accepts such designation, as its Designated Lender under the Credit Agreement.

2. The Designating Lender makes no representations or warranty and assumes no responsibility with respect to the financial condition of the Borrower or the performance or observance by the Borrower of any of its obligations under the Credit Agreement or any other instrument or document furnished pursuant thereto.

3. The Designated Lender (i) confirms that it has received a copy of the Credit Agreement, together with copies of the financial statements referred to in Article V and Article VI thereof and such other documents and information as it has deemed appropriate to make its own credit analysis and decision to enter into this Designation Agreement; (ii) agrees that it will, independently and without reliance upon the Agent, the Designating Lender or any other Lender and based on such documents and information as it shall deem appropriate at the time, continue to make its own credit decisions in taking or not taking any action it may be permitted to take under the Credit Agreement; (iii) confirms that it is an Eligible Designee; (iv) appoints and authorizes the Designating Lender as its administrative agent and attorney-in-fact and grants the Designating Lender an irrevocable power of attorney to receive payments made for the benefit of the Designated Lender under the Credit Agreement and to deliver and receive all communications and notices under the Credit Agreement, if any, that Designated Lender is obligated to deliver or has the right to receive thereunder; (v) acknowledges that it is subject to and bound by the confidentiality provisions of the Credit Agreement (except as permitted under Section 12.4 thereof); and (vi) acknowledges that the Designating Lender retains the sole right and responsibility to vote under the Credit Agreement, including, without limitation, the right

to approve any amendment, modification or waiver of any provision of the Credit Agreement, and agrees that the Designated Lender shall be bound by all such

votes, approvals, amendments, modifications and waivers and all other agreements of the Designating Lender pursuant to or in connection with the Credit Agreement.

4. Following the execution of this Designation Agreement by the Designating Lender, the Designated Lender and the Borrower, it will be delivered to the Agent for acceptance and recording by the Agent. The effective date of this Designation Agreement shall be the date of acceptance thereof by the Agent, unless otherwise specified on the signature page hereto (the "Effective Date").

5. Upon such acceptance and recording by the Agent, as of the Effective Date (a) the Designated Lender shall have the right to make Loans as a Lender pursuant to Article II of the Credit Agreement and the rights of a Lender related thereto and (b) the making of any such Loans by the Designated Lender shall satisfy the obligations of the Designating Lender under the Credit Agreement to the same extent, and as if, such Loans were made by the Designating Lender.

6. Each party to this Designation Agreement hereby agrees that it shall not institute against, or join any other Person in instituting against, any Designated Lender any bankruptcy, reorganization, arrangement, insolvency or liquidation proceeding or other proceedings under any federal or state bankruptcy or similar law for one year and a day after payment in full of all outstanding senior indebtedness of any Designated Lender; provided that the Designating Lender hereby agrees to indemnify, save and hold harmless each other party hereto for any loss, cost, damage and expense arising out of its inability to institute any such proceeding against such Designated Lender. This Section 6 of the Designation Agreement shall survive the termination of this Designation Agreement and termination of the Credit Agreement.

7. This Designation Agreement shall be governed by, and construed in accordance with, the internal laws (including §735 ILCS 105/5-1 et seq. but otherwise without regard to the conflicts of laws provisions) of the State of Illinois.

IN WITNESS WHEREOF, the parties have caused this Designation Agreement to be executed by their respective officers hereunto duly authorized, as of the date first above written.

Effective Date[7]:

[NAME OF DESIGNATING LENDER]

By: ______________________________

Name: ____________________________

Title: _____________________________

[NAME OF DESIGNATED LENDER]

By: ______________________________

Name: ____________________________

Title: _____________________________

OGE ENERGY CORP.

By: ______________________________

Name: ____________________________

Title: _____________________________

Accepted and Approved this
____ day of ________, ____

BANK ONE, NA (having its principal place of business in Chicago, IL), as Agent

By: ______________________________
Title:_____________________________

7 This date should be no earlier than the date of acceptance by the Agent.

Exhibit 10.23

AMENDED AND RESTATED

FACILITY OPERATING AGREEMENT

for the

MCCLAIN GENERATING FACILITY

by and between

OKLAHOMA MUNICIPAL POWER AUTHORITY

and

OKLAHOMA GAS AND ELECTRIC COMPANY

dated as of December 17, 2003

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FACILITY OPERATING AGREEMENT

This AMENDED AND RESTATED FACILITY OPERATING AGREEMENT, dated and effective as of December 17, 2003 (this "Agreement"), is by and between the OKLAHOMA MUNICIPAL POWER AUTHORITY, a governmental agency and body politic and corporate of the State of Oklahoma ("OMPA"), and OKLAHOMA GAS AND ELECTRIC COMPANY, an Oklahoma corporation ("OG&E").

Recitals

A. OMPA and NRG McClain, LLC, a Delaware limited liability company ("NRG McClain"), are joint owners as tenants in common of a 520 MW natural gas-fired combined cycle electric generating facility located in McClain County, Oklahoma (the "Facility") owning a 23% and 77%, respectively, interest in the Facility (the respective ownership interests in the Facility are hereinafter referred to as "Ownership Ratio");

B. Pursuant to the Asset Purchase Agreement dated as of August 18, 2003 by and between OG&E and NRG McClain, OG&E has agreed to purchase all of NRG McClain's right, title and interest in the Facility (the "Power Plant Asset Purchase Agreement") and will become the owner of NRG McClain's right, title and interest in the Facility upon closing of the transactions contemplated by and in accordance with the Power Plant Asset Purchase Agreement (the "Power Plant Closing");

C. Effective as of the date of the Power Plant Closing (the "Effective Date"), OMPA and OG&E own the Facility as tenants in common in accordance with the Amended and Restated Ownership and Operation Agreement (the "O&O Agreement") to be entered into by and between OMPA and OG&E prior to the Effective Date;

D. Pursuant to the Operating and Maintenance Agreement dated as of August 25, 2003, by and between OG&E and OMPA (the "Transmission O & M Agreement"), OG&E agreed to provide operation and maintenance services with respect to the transmission assets (the "Transmission Assets") of the Facility effective as of the Power Plant Closing;

E. Effective as of the Effective Date, OMPA and OG&E agree that OG&E will also provide operation and maintenance services as they relate to the generation assets (the "Generation Assets") of the Facility; and

F. OMPA and OG&E agree that the operation and maintenance services to be provided by OG&E with respect to the Facility shall be exclusively regulated by (i) this Agreement as they relate to the Generation Assets, and (ii) by the Transmission O&M Agreement as they relate to the Transmission Assets.

Agreement

NOW THEREFORE, in consideration of the mutual covenants and agreements set forth in this Agreement, and for other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the parties hereto agree as follows:

ARTICLE I

DEFINITIONS

1.01 Definitions. Terms not otherwise defined in this Agreement shall have the same meanings as set forth in the O&O Agreement. As used in this Agreement, the following terms shall have the meanings specified in this Section 1.01:

"AAA" has the meaning given to it in Section 6.01(c).

"Agreement" has the meaning given to it in the introductory paragraph hereto.

"Approved Capital Budget" means the two year Capital Budget prepared by the Operator pursuant to Section 1(f) of Exhibit A and approved by the Executive Committee pursuant to Section 1(f) of Exhibit A, as may be modified in writing in accordance with the terms of this Agreement.

"Approved Operating Budget" means the Operating Budget prepared and approved by the Executive Committee pursuant to Section 3.04 of the O&O Agreement.

"Approved Operating Plan" means the five year Operating Plan (including major maintenance and capital repairs, and recommended improvements and additions) prepared by Operator based on each Owner's proposed schedule for dispatch of the Facility for the same period pursuant to Section 1(a) of Exhibit A and approved by the Executive Committee pursuant to Section 1(c) of Exhibit A, as maybe modified in writing in accordance with the terms of this Agreement.

"Consumables" means water treatment chemicals, reagents arid other chemicals, lubrication fluids and filters, hydraulic fluids and filters, air filters, ordinary fasteners (nuts, bolts, flails, etc., which are customarily readily available on normal commercial turns), light bulbs and fluorescent tubes, ordinary gasket materials, gloves, flashlights, batteries, disposable safety equipment and first aid supplies, replacement hand tools, solder and welding rods, all supplies for maintenance and plant cleaning materials and supplies, and all other items commonly considered to be consumables within operations of similar facilities.

"Demand" has the meaning specified in Section 6.01(c).

"Dispatch Schedule" means the schedule that shows the required generation and fuel for the relevant time period as published by Owner.

"Environmental Incident" means an environmentally-related event at a Facility that a) has a material impact on human health, welfare or the environment or has the potential to cause such an impact, b) is or has the potential to be a material breach of compliance with any environmental laws, rules or regulations, c) attracts or has the potential to attract widespread negative media attention, and/or d) represents or has the potential to represent a material adverse economic impact on Facility operations.

"Facility" means the electric generation facility located on the Site and associated natural gas, water and waste water pipelines, pumping and meter stations and electric facilities on the Owners' side of the interconnection point, in each case, including any additions, expansions, enhancements, improvements and betterments.

"Facility Employees" means the suitable, qualified, competent and experienced personnel employed by Operator to provide Operator's operation and maintenance services in accordance with this Agreement.

"Hazardous Waste" means waste with inherent properties, which make such waste dangerous to manage by ordinary means, including chemicals and other wastes defined as hazardous at any time during the term of this Agreement by the State of Oklahoma or by any applicable Legal Requirements.

"Legal Requirement" means all laws, statutes, codes, ordinances, Permits, orders, awards, judgments, decrees, injunctions, rules, regulations, authorizations, consents, approvals, orders, franchises, licenses, directions and requirements of all governments or governmental units, courts or arbitrators, which now or at any time hereafter may be applicable to or affect the Facility or any part thereof or any streets, alleys, passageways, sidewalks, curbs, or gutters adjoining the Facility or any part thereof or any use or condition of the Facility or any part thereof or the acquisition, construction, ownership, use or operation of the Facility or any part thereof, except those the non-compliance as to which will not have a material adverse effect on the acquisition, construction, ownership or operation of the Facility.

"LTSA" means that certain Long Term Service Agreement, dated as of December 29, 1999, by and between OG&E and General Electric International, Inc., as such agreement has been or may be amended, supplemented, restated or otherwise modified.

"OG&E" has the meaning given to it in the recitals hereto.

"O&O Agreement" has the meaning given to it in the Recitals.

"OMPA" has the meaning given to it in the recitals hereto.

"O&M Manual" means the operating manuals for the Facility provided by any construction contractor pursuant to any contract for the construction of the Facility, and the operating data, design drawings, specifications, vendor manuals, and similar materials provided by an Owner or any construction contractor to Operator with respect to the Facility.

"Permits" means all of the consents, approvals, authorizations, directions, licenses, waivers and permits issued by any federal, state or local agency or authority to an Owner or the Operator with respect to the ownership, construction, operation and maintenance of the Facility in a safe and commercially sound manner.

"Plant Expenses" means all costs and expenses associated with the services to be provided by the Operator under this Agreement (adjusted, to the extent applicable, for payments by Owners of their Variable Operating Maintenance Share). Plant Expenses are generally divided into Direct Costs (including a mark-up of 5% of all Direct Costs) and Direct

Assessments as listed on Exhibit B hereto. OMPA and OG&E agree that Direct Costs and Direct Assessments are directly related to the operation of the Facility, and that the 5% mark-up with respect to Direct Costs represents a reasonable approximation of administrative and general costs that are directly related to the operation of the Facility but not specifically traceable except with undue difficulty. OG&E and OMPA further agree that the account numbers listed on Exhibit B with respect to the Direct Costs and the Direct Assessments, respectively, reflect the current list of such accounts, but that such account numbers may change from time to time to adequately reflect all Plant Expenses to be allocated between OG&E and OMPA.

"Prudent Operating Practices" has the meaning ascribed to in the O&O Agreement.

"Rules" has the meaning specified in Section 6.01(c).

"Site" means the parcel of land described in the Special Warranty Deed set forth in Section 2.01(a)(i) of the Disclosure Schedule to the Asset Purchase Agreement, dated as of December 13, 2000, between OMPA and Duke Energy McClain, LLC, a Delaware limited liability company, pursuant to which OMPA acquired a 23.0% undivided interest in the Power Plant as a tenant in common.

1.02 Interpretations. In this Agreement, unless clear contrary intention appears: (i) the singular number includes the plural number and vice versa; (ii) reference to any Person includes such Person's successors and assigns but, if applicable, only if such successors and assigns are permitted by this Agreement, and reference to a Person in a particular capacity excludes such Person in any other capacity; (iii) reference to any gender includes each other gender; (iv) reference to any agreement (including this Agreement), document or instrument means such agreement, document or instrument as amended or modified and in effect from time to time in accordance with the terms thereof and, if applicable, the terms hereof; (v) reference to any Article, Section, Schedule or Exhibit means such Article, Section, Schedule or Exhibit to this Agreement, and references in any Article, Section, Schedule, Exhibit or definition to any clause means such clause of such Article, Section, Schedule, Exhibit or definition; (vi) "hereunder," "hereof," "hereto," "herein" and words of similar import are reference to this Agreement as a whole and not to any particular Section or other provision hereof; (vii) relative to the determination of any period of time, "from" means "from and including," "to" means "to but excluding" and "through" means "through and including"; (viii) "including" (and with correlative meaning "include") means including without limiting the generality of any description preceding such term; and (ix) reference to any law (including statutes and ordinances) means such law as amended, modified, codified or reenacted, in whole or in part, and in effect from time to time, including rules and regulations promulgated thereunder.

ARTICLE II

OPERATIONS AND MAINTENANCE; PAYMENTS

Operations and Maintenance Services. OMPA acknowledges and agrees that OG&E will become, as of the Effective Date, the Operator of the Facility pursuant to the Ownership and Operation Agreement. OG&E's sole obligation pursuant to this Agreement shall

be to make available to OMPA those operations and maintenance services to be provided with respect to the Facility by OG&E in accordance with Exhibit A to this Agreement and any major maintenance contracts for which OMPA is obligated to make payments pursuant to Section 2.02, including in each case, to the extent of OMPA's Ownership Ratio, any damages or other amounts payable to such other parties thereunder. In connection therewith, OG&E shall be solely liable for all payments to be made in providing the operation and maintenance services listed on Exhibit A hereto and shall have sole responsibility for the obligations of the "Owner" under Exhibit A. For this purpose, arrangements with third parties for services that are incidental to the primary function of the Facility, *e.g.*, an arrangement for the repair or major maintenance of the Facility, shall not be treated as a contract for the operation of the Facility, provided that the scope of any such arrangement is confined to services that are incidental; the duration of any such arrangement is limited to the period of time needed to perform such services; and the payments for such services under any such arrangement are a substantially predetermined amount (including, e.g., "cost plus") which is not based on the revenues or profits that may be derived from the Facility.

2.01 Payments for Service. OG&E shall invoice OMPA monthly for OMPA's Ownership Ratio of the Plant Expenses adjusted, to the extent applicable, for OG&E's and/or OMPA's Variable Operating Maintenance Share (as defined in the O&O Agreement).

2.02 Settlement of Overdelivery Charges. OG&E and OMPA are each parties to separate agreements for transmission of fuel to the Power Plant with a third-party provider, Oneok Transportation, LLC ("Oneok"). Pursuant to an understanding among OG&E, OMPA and Oneok, OG&E will be charged by Oneok any same day or next day overdeliveries caused by either OG&E and OMPA. OG&E and OMPA therefore agree that OG&E may invoice OMPA in accordance with Section 2.01 of this Agreement on a monthly basis for any overdelivery charges caused by OMPA.

2.03 Invoice or Payment Disputes or Errors. If either OG&E or OMPA discovers an error in the amount of any invoice or payment made pursuant to this Article II or if OMPA disputes a payment requested pursuant to this Article II, such party shall notify the other party within 60 days of discovery of such dispute or error, provided that neither party shall be entitled to correction of any such error if notice of such error is not delivered in writing to the other party within three years of the applicable invoice or payment. If OMPA disputes the amount of any invoice, it shall nevertheless pay the full amount of such invoice, subject to a right to a refund if the dispute is resolved in OMPA's favor, and failure to pay such amount in dispute shall be deemed to be a default hereunder. Any disputes resulting from this Article II shall be settled in accordance with the provisions of Article VI.

2.04 Interest on Late Payments. Any amounts (a) disputed and subsequently found to have been correctly invoiced or owed, or (b) not timely paid in accordance with this Agreement shall accrue interest at the lesser of (i) the then effective prime rate of Citibank, N.A. plus 5%, or (ii) the highest rate permitted by applicable law, from the day on which such amounts become due and owing to the day on which such amounts and the interest thereon are paid. OMPA and

OG&E intend that this Agreement shall at all times comply with applicable law now or hereafter in effect governing interest payable hereunder. If the applicable law is ever revised, repealed, or judicially interpreted so as to render usurious any amount called for under

this Agreement, then all excess amounts theretofore collected shall be credited to the then applicable principal balance hereunder or be refunded, and this Agreement shall immediately be deemed to have been reformed and the amounts thereafter collected hereunder reduced, without the necessity of the execution of any new document, so as to comply with the then applicable law, but to permit the recovery of the fullest amount otherwise called for hereunder.

2.05 Audit. During ordinary business hours and upon reasonable notice to OG&E, OMPA may inspect, copy and audit OG&E's books, records, accounts, ledgers, time cards, estimates, schedules, correspondence and other documents related to OG&E's performance of its obligations hereunder and amounts due to OG&E hereunder; provided, however, that any audit of line item "Salaries – Incentive Pay" listed on Exhibit B hereto shall be limited to determining that any payments made by OG&E to employees at the Facility have been made consistent with payout amounts received by employees of OG&E at other power plants. OG&E agrees to keep such records for five years following their respective preparation (at which time it will be permitted to destroy such books and records in the ordinary course of business) and will furthermore keep any such books and records not previously destroyed in the ordinary course of business, for five years after the termination of this Agreement, and shall provide copies to OMPA upon request, at OMPA's expense. OMPA's acceptance or approval or payment of OG&E's charges shall not operate as a waiver of OMPA's right to audit OG&E in accordance with this Section 2.05.

ARTICLE III

TERM OF AGREEMENT; TERMINATION

3.01 Term. This Agreement shall become effective as of the Effective Date and shall remain in effect until, and shall terminate automatically without any further action by the parties hereto on the Termination Date as defined in the O&O Agreement.

3.02 Termination. Notwithstanding anything in Section 2.01 to the contrary, upon termination of this Agreement pursuant to Section 3.01, and in addition to any amounts payable by OMPA through the effective date of such termination pursuant to Article II, OG&E shall be entitled to a payment equal to OMPA's Ownership Ratio of all ordinary and necessary costs, losses or expenses incurred by OG&E as a direct consequence of the termination, including costs for claims arising out of the termination of subcontracts and costs incurred in assisting OG&E and OMPA by preserving and protecting work in progress.

ARTICLE IV

REPRESENTATIONS AND WARRANTIES

4.01 OG&E Representations. OG&E represents and warrants to OMPA as follows:

(a) Standing. OG&E is a corporation duly formed and validly existing under the laws of the State of Oklahoma. OG&E has full corporate power and authority to execute and deliver this Agreement and to perform its obligations hereunder. OG&E is qualified, and during

the term of this Agreement shall continue to be qualified, to do business in the State of Oklahoma. The execution and delivery by OG&E of this Agreement and the performance by OG&E of its obligations hereunder have been duly and validly authorized by all requisite corporate action on the part of OG&E. The execution and delivery by OG&E of this Agreement do not, and the performance by OG&E of its obligations under this Agreement will not, violate any provision of any laws, OG&E's constitutive documents or any indenture, agreement or instrument to which OG&E is a party, or by which OG&E or its property may be bound or affected. This Agreement has been duly and validly executed and delivered by OG&E and constitutes the legal valid and binding obligation of OG&E enforceable against OG&E in accordance with its terms, except as the same may be limited by bankruptcy, insolvency, reorganization, arrangement, moratorium or other similar laws relating to or affecting the rights of creditors generally, or by general equitable principles.

(b) No Violation of Law. OG&E is not in violation of any applicable laws or any judgment entered by any federal, state or local governmental authority, which violations or judgments, individually or in the aggregate, would affect OG&E's ability to perform its obligations under this Agreement. Neither the execution, delivery and performance by OG&E of its obligations under this Agreement, nor the consummation of the transactions contemplated hereby, will violate any authorizations, consents, exemptions, decrees, licenses, policies, interpretations, guidelines, permits, certificates, regulations, orders and approvals of and from any federal, state, county or local governmental entity of which OG&E is or upon exercise of reasonable diligence should be aware or any laws, rules, regulations or orders of any Governmental Authority.

4.02 OMPA Representations. OMPA represents and warrants to OG&E as follows:

(a) Standing. OMPA is a governmental agency and body politic and corporate of the State of Oklahoma, validly existing and in good standing under the laws of the State of Oklahoma. OMPA has full power and authority to enter into this Agreement and to perform its obligations hereunder. The execution and delivery by OMPA of this Agreement and the performance by OMPA of its obligations hereunder have been duly and validly authorized by its Board of Directors, no other action on the part of OMPA being necessary. The execution and delivery by OMPA of this Agreement do not, and the performance by OMPA of its obligations under this Agreement will not, violate any provision of any laws, Title 11, Sections 24-101 et seq. of the Oklahoma Statutes, the constitutive documents of OMPA or any indenture, agreement or instrument to which OMPA is a party, or by which OMPA's property may be bound or affected. This Agreement has been duly and validly executed and delivered by OMPA and constitutes the legal, valid and binding obligation of OMPA enforceable against OMPA in accordance with its terms except as the same may be limited by bankruptcy, insolvency, reorganization, arrangement, moratorium or other similar laws relating to or affecting the rights of creditors generally, or by general equitable principles

(b) No Violation of Law. OMPA is not in violation of any applicable laws or any judgment entered by any federal, state or local governmental authority, which violations or judgments, individually or in the aggregate, would affect OMPA's ability to perform its obligations under this Agreement. Neither the execution, delivery and performance by OMPA of its obligations under this Agreement, nor the consummation of the transactions contemplated hereby, will violate any authorizations, consents, exemptions, decrees, licenses, policies, interpretations, guidelines, permits, certificates, regulations, orders and approvals of and from any federal, state, county or local governmental entity of which OMPA is or upon exercise of reasonable diligence should be aware or any laws, rules, regulations or orders of any Governmental Authority.

ARTICLE V

MISCELLANEOUS

5.01 Entire Agreement. This Agreement, the O&O Agreement, the Schedule and Exchange Agreement, the Transmission Services Agreement, the Fuel Agreement, the Market Dispatch Agreement and the Service Agreement For Power Sales Between OMPA and OG&E contain the entire understanding of the parties with respect to the subject matter hereof and thereof and supersede all prior agreements and commitments with respect thereto, including that certain Memorandum of Understanding regarding the O&O Agreement between OG&E and OMPA dated September 15, 2003 . There are no oral understandings, terms or conditions and neither party has relied upon any representation, expressed or implied, not contained in this Agreement or the agreements expressly referenced herein. This Agreement may be signed in counterparts.

5.02 Amendments. No change, amendment, or modification of this Agreement shall be valid or binding upon the parties hereto unless such change, amendment, or modification shall be in writing and duly executed by the parties hereto.

5.03 Captions. The captions and subheadings contained in this Agreement are for convenience and reference only and in no way define, describe, extend, or limit the scope or intent of this Agreement or the intent of any provision contained herein.

5.04 Notices. Except as otherwise expressly provided herein, any notice, demand, offer, or other instrument required or permitted to be given pursuant to this Agreement shall be in writing, signed by the party giving such notice, demand, offer, or other instrument and shall be delivered by telecopier, hand delivery, registered or certified mail, return receipt requested, postage prepaid, or nationally recognized overnight courier to the other party at the address set forth below:

If to OMPA:

Oklahoma Municipal Power Authority

Street Address:
2300 East Second Street
Edmond, OK 73034

Post Office Address:
P.O. Box 1960
Edmond, OK 73083-1960

Facsimile No. (405) 359-1071
Attn: General Manager

With a copy to:

Oklahoma Municipal Power Authority

Street Address
2300 East Second Street
Edmond, OK 73034

Post Office Address:
P.O. Box 1960
Edmond, OK 73083-1960

Facsimile No. (405) 359-1071
Attn: General Counsel

If to OG&E:

Oklahoma Gas and Electric Company
PO Box 321
Oklahoma City, Oklahoma 73101-0321
Attention: Jack T. Coffman,
Senior Vice President, Power Supply
Facsimile No.: (405) 553-3198

With a copy to:

Jones Day
77 West Wacker Drive, Suite 3500
Chicago, Illinois 60601-1692
Attention: Peter D. Clarke
Facsimile No.: (312) 782-8585

Each party shall have the right to change the place to which notice, demand, offer, or other instrument shall be sent or delivered by similar notice sent in like manner to the other party. The effective date of any notice, demand, offer, or other instrument issued pursuant to this Agreement shall be the date (a) of delivery, if delivered by telecopier with answer back confirmation, (b) when delivered, if hand delivered, (c) if sent by overnight courier, one business day after delivery to such courier, and (d) if sent by registered or certified mail, three business days after being deposited in U.S. mail.

5.05 Severability. The invalidity of one or more of the provisions or sections contained in this Agreement shall not affect the validity of the remaining portion of the Agreement so long as the material purposes of this Agreement can be determined and effectuated. In the event that any portion or all of this Agreement is held to be void or unenforceable, the parties agree to negotiate in good faith to reach an equitable agreement on such portion that is void or unenforceable which shall effect the intent of the parties as set forth in this Agreement. In the event that the parties do not mutually agree on what changes to make, if any, within 60 days after the such portion or all of this Agreement is held to be void or unenforceable, either party may initiate the dispute resolution procedures set forth in Article VI with respect to the obligation to negotiate in good faith.

5.06 Assignment. This Agreement shall be binding upon, shall inure to the benefit of, and may be performed by, the successors and assigns of the parties hereto. No assignment, pledge, or other transfer of this Agreement by either party shall be made without the other party's prior written consent, nor shall it operate to release the assignor, pledgor, or transferor from any of its obligations under this Agreement.

5.07 No Waiver. Any failure of either party to enforce any of the provisions of this Agreement or to require compliance with any of its provisions at any time during the pendency of this Agreement shall in no way affect the validity of this Agreement, or any part hereof, and shall not be deemed a waiver of the right of either party thereafter to enforce any and each such provision.

5.08 Governing Law. THIS AGREEMENT SHALL BE GOVERNED BY, CONSTRUED, INTERPRETED AND ENFORCED IN ACCORDANCE WITH, THE SUBSTANTIVE LAW OF THE STATE OF OKLAHOMA WITHOUT REFERENCE TO ANY PRINCIPLES OF CONFLICTS OF LAWS THEREOF.

5.09 No Partnership Created. Nothing contained in this Agreement shall be construed as constituting a joint venture or partnership between OMPA and OG&E.

5.10 Consequential Damages. Neither party shall in any event be responsible or liable to the other party for consequential damages, including, without limitation, liability for loss of use of the Facility or existing property, loss of profits, loss of product or business interruption, however caused, except to the extent any indemnification hereunder is deemed to be consequential damages.

5.11 Limitations Application. Neither party makes any representations, covenants, warranties or guarantees, express or implied, other than those expressly set forth

herein. The parties' rights, liabilities, responsibilities and remedies with respect to the obligations to be performed under this Agreement, whether in contract or otherwise, shall be exclusively those expressly set forth in this Agreement.

5.12 Survival. The provisions of Section 2.04, Section 5.11, this Section 5.12 and Article VI shall survive the termination of this Agreement without limitation.

5.13 Interpretation. The parties intend that this Agreement shall comply with Rev. Proc. 97-13, and this Agreement shall be interpreted accordingly.

ARTICLE VI

DISPUTE RESOLUTION

6.01 Dispute Resolution; Arbitration.

(a) Any dispute or claims arising under this Agreement which cannot be resolved by the parties through negotiation by the parties' managers shall be referred to a panel consisting of a senior executive of each party, with authority to decide or resolve the matter in dispute, for review and resolution. Such senior executives shall attempt to meet and resolve the dispute within 30 days.

(b) If the parties are unable to resolve a dispute as provided in Section 6.01, each party has the right to (i) pursue any legal and/or equitable remedies in the District Court of Oklahoma County or such other court of proper jurisdiction or (ii) seek to arbitrate the dispute using the procedures specified in Section 6.01(c); which election shall be binding upon such party with respect to the dispute at issue.

(c) If so elected by a party and the other party agrees in writing, a dispute shall be arbitrated in accordance with the following procedures:

(1) At the request of either party upon written notice to that effect to the other party (a "Demand"), the dispute shall be finally settled by binding arbitration before a panel of three arbitrators in accordance with the Commercial Arbitration Rules (the "Rules") of the American Arbitration Association ("AAA") then in effect, except as modified herein. The Demand must include statements of the facts and circumstances surrounding the dispute, the legal obligation breached by the other party, the amount in controversy and the requested relief accompanied by all relevant documents supporting the Demand.

(2) Unless the parties otherwise agree, arbitration shall be held in the headquarters cities of the parties alternating locations between sessions or meetings with the arbitrator(s) and beginning, for each arbitrated dispute, with the headquarters city of the party not making the Demand. The arbitration shall be governed by the United States Arbitration Act, 9 U.S.C. §§ 1 et seq.

(3) Each party shall select one arbitrator within ten days of the receipt of the Demand, or if

such party to the dispute fails to make such selection within

ten days from the receipt of the Demand, the AAA shall make such appointment. The two arbitrators thus appointed shall select the third arbitrator, who shall act as the chairman of the panel. If the two arbitrators fail to agree on a third arbitrator within 30 days of the selection of the second arbitrator, the AAA shall make such appointment.

(4) The award shall be in writing (stating the award and the reasons therefor) and shall be final and binding upon the parties, and shall be the sole and exclusive remedy between the parties regarding any claims, counterclaims, issues, or accountings presented to the arbitral panel. The arbitral panel shall be authorized in its discretion to grant pre-award and post-award interest at commercial rates. Judgment upon any award may be entered in any court having jurisdiction. For purposes of a pre-arbitral injunction, pre-arbitral attachment or other order in aid of arbitration proceedings, the parties hereby agree to submit to the jurisdiction of the United States federal courts located in, and the local courts of, the State of Oklahoma. Each of the parties irrevocably waives, to the fullest extent permitted by law, any objection it may now or hereafter have to the jurisdiction of such courts or the laying of the venue of any such proceeding brought in such a court and any claim that any such proceeding brought in such a court has been brought in an inconvenient forum. Each of the parties hereby consents to service of process by registered mail at its address set forth herein and agrees that its submission to jurisdiction and its consent to service of process by mail is made for the express benefit of the other party.

(5) This Agreement and the rights and obligations of the parties shall remain in full force and effect pending the award in any arbitration proceeding hereunder.

(6) Unless otherwise ordered by the arbitrators, each party shall bear its own costs and fees, including attorneys' fees and expenses. The parties expressly agree that the arbitrators shall have no power to consider or award any form of damages barred by Section 5.10, or any other multiple or enhanced damages, whether statutory or common law.

(7) The parties, to the fullest extent permitted by law, hereby irrevocably waive and exclude any rights of application or appeal or rights to state a special case for the opinion of the courts or any other recourse to the court system other than to enforce the agreement to arbitrate pursuant to this Section 3.13(c) for attachment or other order in aid of arbitration proceedings or to enforce the award of the arbitral panel.

(8) During the pendency of any dispute, the parties shall continue to perform the obligations imposed upon them under this Agreement to the fullest extent possible, consistent with their positions in dispute.

6.02 Performance During Dispute. During the pendency of any dispute, the parties shall continue to perform the obligations imposed upon them under this Agreement to the fullest extent possible, consistent with their positions in dispute.

IN WITNESS WHEREOF, the parties have executed this Agreement as of the date first above written.

OKLAHOMA MUNICIPAL POWER AUTHORITY

By: /s/ Roland Dawson

Name: Roland Dawson
Title: General Manager and Assistant Secretary

OKLAHOMA GAS AND ELECTRIC COMPANY

By: /s/ Jack T. Coffman

Name: Jack T. Coffman
Title: Senior Vice President, Power Supply

EXHIBIT A
to
Facilities Operating Agreement,

Operations & Maintenance

Schedule of Duties and Responsibilities

Operator shall administer, operate and maintain the Facility in accordance with the Approved Operating Plan, the Approved Operating Budget, the Approved Capital Budget, the Dispatch Schedule, Prudent Operating Practices, all Legal Requirements, the O&M Manuals and the relevant insurance policies. Operator shall be responsible for and perform the following tasks:

1. ***Administrative.*** Plan, budget, schedule and conduct all business related to the operation and maintenance of the Facility.

(a) Operating Plan. Operator shall provide to the Executive Committee a five year Operating Plan, including budget estimates, which shall set forth all underlying assumptions (including emissions data) and implementation plans in connection with the operation and maintenance of the Facility. The Operating Plan shall include: (a) routine operational services; (b) routine repairs and maintenance for each part of the Facility; (c) information regarding the inventory and proposed procurement of equipment, spare parts, tools and, in the case of major equipment, the residual life thereof; (d) routine operational information, general operating data and other Facility data; (e) scheduled outages; (f) consumable items; (h) staffing plans (i) Operator's environmental plan describing any actions necessary to ensure that the Facility will comply with all applicable environmental Legal Requirements; and (j) Operator's recommendations on matters affecting the operation and maintenance of the Facility, including any relevant capital improvements, additions or other expenditures for the Year.

(b) Operating Budget. Operator shall prepare and provide to the Executive Committee a Budget Estimate in accordance with Section 3.04(b) of the O&O Agreement. Furthermore, Operator shall prepare (based on the Budget Estimate) and provide, and the Executive Committee shall approve, the Operating Budget in accordance with Section 3.04(b) of the O&O Agreement. The Operating Budget shall be itemized on a monthly GAAP basis and shall incorporate all project operating costs.

(c) Approval of Operating Plan and Operating Budget.

(1) Each Owner shall provide the Operator a Dispatch Schedule, including "best estimates" for capacity factor, expected load cycling duty and quality and type of fuel.

(2) Operator shall prepare the Operating Plan, the Budget Estimate and the Operating Budget based on the Dispatch Schedule and shall add proposed scheduled outage information. Any modifications to the Approved Operating

Plan or the Approved Operating Budget required as a result of changes in the foregoing not attributable to Operator should be deemed modifications made at the Executive Committee's request.

(3) Not later than (i) December 31, 2003, with respect to the Year in which the Effective Date occurs, and (ii) ninety (90) days prior to the beginning of each subsequent Year, Operator shall submit to the Executive Committee, for the Executive Committee's review and approval, the proposed Operating Plan.

(4) Within thirty (30) days of the Executive Committee's receipt of a proposed Operating Plan and the Budget Estimate, the Executive Committee shall provide comments to Operator with respect thereto and request any additions, changes or modifications thereto. Not more than ten (10) days following Operator's receipt of the Executive Committee's comments on the proposed Operating Plan and Budget Estimate, the Executive Committee and Operator shall meet to discuss the terms of such Operating Plan and Budget Estimate and the Executive Committee's requested changes thereto. Operator and the Executive Committee shall use reasonable efforts to reach agreement thereon. Upon approval by the Executive Committee, such Operating Plan shall be the Approved Operating Plan and the Budget Estimate shall be the basis for the Approved Operating Budget for the applicable Year.

(d) Operating Budget Overruns/Underruns. If at any time Operator reasonably anticipates that the aggregate costs of operating and maintaining the Facility may exceed the amount set forth in the applicable Approved Operating Budget by more than 10% or be 10% below the amount set forth in the applicable Approved Operating Budget, Operator shall promptly advise the Executive Committee of such situation by Notice and propose for the Executive Committee's approval any changes to the Approved Operating Budget which Operator considers necessary.

(e) Revisions to Operating Plan and Operating Budget. At the request of the Executive Committee, or to the extent Operator itself determines necessary or appropriate, Operator shall update the applicable Operating Plan or Operating Budget at such times as may be appropriate to reflect changes in assumptions made in their preparation. These updates shall be submitted to the Executive Committee for its approval. In addition, Operator may, at any time, provide proposed revisions to any Operating Plan or Operating Budget to the Executive Committee for consideration. Unless otherwise specified by the Executive Committee, such revisions shall become effective for purposes of this Agreement from the date of the Executive Committee's approval thereof (if approved), and shall be applied to the first calendar month to which such revision relates following such approval or resolution.

(f) Capital Budget. In conjunction with, the preparation of the Operating Plan and Operating Budget, Operator shall determine the necessity for and cost of capital improvements. Major Capital Projects and routine annual capital improvements shall be included in the Operating Plan. A two-year Capital Budget shall be prepared and submitted to Owner by Operator at the time of submission of the Operating Plan and Operating Budget. The Executive Committee shall review and approve the two-year Capital Budget as provided herein.

(g) Inventory. Prepare a spare parts and inventory program for approval by the Executive Committee in accordance with Section 3.03 of the O&O Agreement.

(h) Security Program. Develop and implement a security program, including provisions for third-party access to the site and Facility.

(i) Safety Procedures. Develop and maintain safety procedures, a safety manual, and an effective safety program including fire and explosion safety measures.

(j) Operating Workforce. Develop an effective and sufficient operating work force through appropriate on-going hiring, training, administration, and compensation programs in conjunction with Owners.

(k) Financial Reports. Provide detailed financial and operating reports with Approved Operating Budget comparisons.

(l) Periodic Reports. Prepare and provide periodic reports on behalf of and at the request of Owners.

(m) Information Requests. Respond in a timely manner to written requests for Facility information from Owners.

(n) Employment Insurance. Obtain and maintain such workers' compensation, unemployment and other employee related insurance as is required by applicable state law.

(o) Maintenance Program. Develop, implement and regularly update a maintenance program that is intended to minimize life cycle maintenance costs and maximize intervals between major maintenance outages, does not invalidate equipment manufacturers' warranties, specifications and recommendations or Prudent Operating Practices, and meets the requirements of the authorized insurance inspector.

(p) O&M Consulting. Provide such operating and maintenance consulting services to Owners as it may deem necessary or desirable. Costs of such services shall be included in the Two Year Operating Budget.

(q) Insurance. Obtain and maintain required and appropriate levels of insurance.

(r) Permits. Reasonably assist Owners in obtaining all necessary Permits in connection with the Facility.

(s) Meter Reading. Read and confirm readings of all meters associated with the Facility.

(t) Accounting Records. Provide accounting records and data to support monthly, quarterly, year-end or other reports.

(u) Invoices. Review and approve all invoices. Obtain Owners approval for costs that exceed the Approved Operating Budget limits.

(v) Cost Ledgers. Maintain true, complete and accurate cost ledgers and accounting records in accordance with generally accepted accounting principles ("GAAP").

(w) Notices. Provide appropriate notices to Owners in a timely manner.

(x) Revisions. Provide proposed revisions to the Operating Plan and the Operating Budget based on changes in Owners expected Dispatch Schedule for the relevant period, and fuel and/or other contracts. Items approved by Owners will be considered approved additions to the Operating Plan and the Operating Budget.

(y) Adequate Records. Maintain true, complete and accurate operating logs, records and reports necessary or required by applicable Legal Requirements and Project Agreements or beneficial for proper operation and maintenance of the Facility in accordance with Prudent Operating Practices.

(z) Manuals. Maintain drawings, instruction books and operating and maintenance manuals and procedures, and revise drawings and manuals as modifications are made. Cooperate with and assist Owners' personnel in obtaining and maintaining required Legal Requirements.

(aa) Unrestricted Access. Provide Owners and Owners' designees with unrestricted access to the Facility in accordance with the normal site safety and security procedures and cooperate with Owners and their designees in all Owner inspections of the Facility. Such inspections may occur on any business day without Notice at any time and shall not unreasonably interfere with personnel safety or the operation and maintenance of the Facility.

2. ***Operation and Maintenance.***

(a) Operate and maintain the Facility in a clean, safe and efficient manner and in accordance with Prudent Operating Practices.

(b) Operate the Facility in accordance with the Approved Operating Plan and the Approved Operating Budget. If a new Operating Plan and/or a new Operating Budget is not timely approved by Owners, operate in accordance with the preceding Approved Operating Plan and/or Approved Operating Budget until a new Operating Plan and/or a new Operating Budget is approved.

(c) Operator may initiate work on a condition that constitutes a safety, environmental issue or something that could damage the plant without prior approval from the Owners. The operator shall notify the Owners as soon as practicable.

(d) Maintain all tools and instruments necessary to operate and maintain the Facility.

(e) Purchase and inventory spare parts, materials, and supplies (including Consumables and items covered by Plant Office Expenses and Rolling Stock Expenses) as per the approved spare parts program.

(f) Schedule and perform or cause to be performed the work specified in the maintenance program in accordance with the Dispatch Schedule, the Approved Operating Plan, the Approved Operating Budget, Prudent Operating Practices, and all Legal Requirements.

(g) Perform periodic operational checks and tests of equipment in accordance with the equipment manufacturers' specifications and recommendations, Prudent Operating Practices and all Legal Requirements, and arrange for required environmental or other required specialized equipment tests to be performed.

Maintain records of the foregoing, including: (i) a register of all equipment subject to inspection by governmental authorities; (ii) a register of all test dates and results; and (iii) a register of Facility operating performance data including operating hours and adjustments to expired hours and expired life, all measurements and records required by Permits and Project Agreements, and maintenance of Facility generating and protective equipment.

(h) Evaluate the nature and impact of any equipment failure and if the failure is major or material, promptly provide notice to Owners and review the situation with Owners and mutually agree on a reasonable remedy of the matter.

(i) Provide for necessary and desirable security services for the Facility in accordance with the security program.

(j) Provide for building, structural and yard maintenance services.

(k) Order, receive and maintain adequate inventories and supplies (parts and Consumables).

(l) Operate and maintain the Facility in such a way as to satisfy all Legal Requirements and Project Agreements, taking such samples and performing and reporting such tests as are required by all Legal Requirements and Project Agreements, and promptly provide Notice to Owner of any areas of Legal Requirements or Project Agreement conflicts, violations or unsatisfactory conditions or test results, including performing all necessary testing and reporting in accordance with Legal Requirements and Project Agreements.

(m) Develop and maintain environmental procedures and an effective environmental program. Dispose of all waste materials, including Hazardous Waste, in accordance with Legal Requirements and Owner's waste disposal agreements.

(n) The Facility shall be operated by the Operator's employees and the Operator shall be fully responsible for all the acts and omissions of all of its operators.

(o) Operator shall provide at least the minimum number of suitably qualified, competent and experienced personnel as may be required satisfactorily to carry out the respective

parts of the services to the performance of which Operator assigns them. Owners shall review labor costs as a part of the approval process of the Operating Budget.

(p) Complete the delivery of fuel supply, including unloading and inventory as required by the Dispatch Schedule, on a day-to-day basis.

(q) Operate to achieve the target Equivalent Availability Factor (EAF) for the plant based upon the Approved Dispatch Schedule, and advise Owners of any risks associated with fuel or dispatch issues, including any recommended curtailments.

(r) Maintain a boiler and pressure vessel repair rating of an 'R-Stamp'.

(s) Provide recommendations to Owners to increase reliability and reduce expenses.

3. ***Environmental Incident Reporting and Evaluation***.

The Operator shall be responsible for immediately notifying all appropriate governmental entities, the Corporate Environmental Health and Safety Department and other deemed appropriate persons in the event of an Environmental Incident. Evidence of all notifications and who was notified shall be placed in the Facility environmental files.

In addition, the Operator shall document and file all critical information regarding each such event.

The Corporate Environmental Health and Safety Department shall be responsible for filing all follow-up reports required by Environmental Law. A copy of such reports shall be placed in the Facility's environmental files.

EXHIBIT B
TO

FACILITIES OPERATING AGREEMENT

OPERATIONS & MAINTENANCE — ACCOUNTING MEMORANDUM

Article II Operations and Maintenance shall be further defined as follows:

1. Each Owner shall pay their respective Ownership Ratio of Direct Costs incurred at the Facility. These costs will include:

   Salaries and wages;
   Employee pensions, benefits, and payroll taxes;
   Other Employee expenses;
   Office equipment and other office expense;
   Communication expense;
   Other direct costs incurred at the power plant; and
   Team Share Incentive pay paid to plant employees.

2. Each Owner shall pay their respective Ownership Ratio of Outside Services which will include any costs associated with the LTSA or its successor.

3. In addition OMPA will pay a 5% adder only with respect to Direct Costs in #1 above. The adder will not be applied to any other costs.

4. OMPA will also pay the following costs allocated to the Facility:

Purchase Overhead allocated based on a percentage of the Direct Costs for materials and services;
P-Card Overhead allocated based on a percentage of the Direct Costs related to P-Card purchases;
Computer Equipment Activity allocated based on number of units at location;
Information System Activity Allocation allocated based on actual number of SAP seats per location;
Power Supply Division costs allocated by Nameplate capacity or other agreed to allocation method; and
Assessments for work performed which are for the direct benefit of the Facility provided such costs can be documented as a Power Plant expense.

5. OMPA will not pay the following types of Assessments: A&G Distrigas, Headcount, Utility Company, or Information Systems or items of a similar nature.

6. Station Power will be billed at OG&E system average fuel cost for the respective month. The tariff rate will no longer apply to station power.

7. In the event a market develops for ancillary services, the parties will mutually negotiate an arrangement that will meet the then applicable tax requirements and

tariff requirements while insuring both parties will receive the Ownership Ratio of any revenues derived from such services.

Direct Costs

GL Account Description	**GL Account Number**
Materials & Supplies Returns (Cr)	601000
Materials & Supplies - Sales Issues	601001
Materials & Supplies - Stock	601002
Materials & Supplies Non Stock	601100
Tools - Unassigned Stock Numbers	601200
Inventory Shrinkage	603100
Office Equip and Other Office Expense	605000
Communications Expense	607000
Utilities	608000
Salaries & Wages - Regular	620000
Salaries & Wages - Overtime	621000
Per diem	622000
Salaries & Wages - Medical/Sickness	629200
Salaries & Wages - Holiday/Vacation	629300
Salaries - Incentive Pay	629500
Temporary Help	631000
Contract Labor	633000
Employee Expenses - Meals	640000
Employee Expenses - Education/Training	640010
Employee Expenses - Other	640020
Employee Expenses - Personal Auto	640030
Employee Expenses-Communication Devi	640040
Trucking Outside	650000
Transportation Maintenance	650100
Transportation Fuel	650110
Fleet Registration Fees	650120
Computer Rentals	670001
Equipment Rentals	670002
Transportation Rentals	670003
Rents - Other	670004
Environmental Expense	676000
Health & Safety Expense	677000
Professional Dues and Subscriptions	680000
Postage	680009
Printing	680010
Miscellaneous Fees and Permits	680015
Professional Services - Legal	682000
Professional Services - Other	682010
Property Insurance	683000
Public Injuries & Damages	684000
Workers Comp Accrual	684010
Empl Pen & Ben-Pension Plan	685000
Empl Pen and Ben -Training	685003

Empl Pen and Ben - Other	685010	

Empl Pen & Ben - Group Life Insurance		685016
Empl Pen & Ben - Group Medical		685017
Empl Pen & Ben- Group Dental		685019
Empl Pen & Ben- Long Term Disability		685020
Empl Pen & Ben- Retirement Savings Plan		685024
Empl Pen & Ben- Retire Saving Restoration Plan		685025
Empl Pen & Ben- Postretirement Life Insurance		685031
Empl Pen And Ben-Physicals, Eyeglass	685033	
Misc Gen Exp - Corporate	689000	
Misc Gen Exp - Corp Association Dues &	689001	
Misc Gen Exp - Conventions/Meetings	689006	
Misc Gen Exp - Other	689007	
Misc Gen Exp - Power Plants Tours	689011	
Taxes - Other - FICA		705020
Taxes - Other - FUTA		705030
Taxes - Other - SUTA		705040
Overhead @5% of Direct Cost		

Direct Assessment

Applicable for work performed on behalf of the Facility only

GL Account Description	GL Account Number
Station Power	Separate Calculation
Outside Services including LTSA	632000
Purchasing OH Applied to Cost Center	780003
P-Card OH Applied to Cost Centers	780004
Labor OH Applied	800000
Purchasing	800003
P-Card	800004
Fully Loaded Labor Activity	800100
Fully Loaded OT Labor Activity	800110
Per Diem	800200
Contr Labor Activity	800310
Contr Equip Activity	800320
Contr Pdiem Activity	800330
Contract Labor/Temporary Labor Activity	800500
Computer Equipment at Plant	800850
Computer Equipment Activity	800851
Info System	800871
Internal Personnel Costs (Production Dept. only)	810010
Assessment Other (Production Dept. only)	810020
External Services (Production Dept. only)	810030
Materials & Supplies (Production Dept. only)	810040
Transportation Activity	865010

Exhibit 10.24

AMENDED AND RESTATED

OWNERSHIP AND OPERATION AGREEMENT

for the

MCCLAIN GENERATING FACILITY

by and between

OKLAHOMA MUNICIPAL POWER AUTHORITY

and

OKLAHOMA GAS AND ELECTRIC COMPANY

dated as of December 17, 2003

TABLE OF CONTENTS

EXHIBITS AND SCHEDULES

OWNERSHIP AND OPERATION AGREEMENT

This OWNERSHIP AND OPERATION AGREEMENT, dated as of December 17, 2003 (this "Agreement"), is made and entered into by and between OKLAHOMA MUNICIPAL POWER AUTHORITY, a governmental agency and body politic and corporate of the State of Oklahoma ("OMPA"), and OKLAHOMA GAS AND ELECTRIC COMPANY, an Oklahoma corporation ("OG&E").

Recitals

A. OMPA and NRG McClain, LLC, a Delaware limited liability company ("NRG McClain"), are joint owners as tenants in common of a natural gas-fired combined cycle electric generating facility nominally rated at 520 MW located in McClain County, Oklahoma (the "Power Plant"), and are parties to the Ownership and Operation Agreement, dated as of March 1, 2001, setting forth certain agreements with respect to the ownership and operation of the Power Plant (the "Original Agreement").

B. Pursuant to the Asset Purchase Agreement dated as of August 18, 2003 by and between OG&E and NRG McClain, OG&E has agreed to purchase all of NRG McClain's right, title and interest in the Power Plant (the "Power Plant Asset Purchase Agreement") and will become the owner of NRG McClain's right, title and interest in the Power Plant upon closing of the transactions contemplated by and in accordance with the Power Plant Asset Purchase Agreement (the "Power Plant Closing").

C. Accordingly, OMPA and OG&E have determined to hereby amend and restate the Original Agreement to set forth their agreements with respect to the ownership and operation of the Power Plant subsequent to, effective as of and expressly conditioned upon, the Power Plant Closing.

Agreement

NOW THEREFORE, in consideration of the mutual covenants and agreements set forth in this Agreement, and for other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the parties hereto agree as follows:

ARTICLE I

DEFINITIONS

1.01 Definitions. As used in this Agreement, the following terms shall have the meanings specified in this Section 1.01:

"AAA" has the meaning given to it in Section 9.02(c)(1).

"Affiliate" means any Person that directly, or indirectly through one or more intermediaries, controls or is controlled by or is under common control with the Person specified. For purposes of this definition, control of a Person means the power, direct or indirect, to direct

or cause the direction of the management and policies of such Person whether by contract or otherwise, and ownership by a Person of twenty five percent (25%) or more of the voting securities or other voting equity interests of another Person shall create a rebuttable presumption that such Person controls such other Person.

"Agreement" has the meaning given to it in the introductory paragraph hereto.

"Ancillary Services" means those services made available by virtue of the Power Plant other than the sale of Capacity, Energy, fuel and capital assets. Such services may include, but shall not be limited to, load following, reserves, storage of fuel and supply or absorption of reactive power.

"Applicable Law" means all laws, statutes, rules, regulations, ordinances and other pronouncements having the effect of law of the United States, any foreign country or any domestic or foreign state, county, city or other political subdivision or of any Governmental Authority.

"Buy-Sell Notice" has the meaning given to it in Section 3.03(i).

"Buy-Sell Procedure" has the meaning given to it in Section 3.03(i).

"Capacity" means the rated continuous ability of the Power Plant to generate Energy and Ancillary Services expressed in megawatts (MW).

"Capital Additions" means additions, improvements and betterments to the Power Plant.

"Claims" means all claims, demands, losses, liabilities and expenses, including reasonable attorney's fees.

"Claiming Party" has the meaning given to that term in Section 9.03(a).

"Costs of Capital Additions" means those costs incurred or to be incurred to effect Capital Additions.

"Costs of Operation" means all costs attributable to the operation and maintenance of the Power Plant, including all amounts payable under the Operating & Maintenance Agreements or any successor agreement, and, without duplication, all direct administrative and general costs plus cost of repairs, renewals and replacements necessary to assure design capability and reliability or that are required by any Governmental Authority. Costs of Operation shall not include (i) payments in lieu of property Taxes, (ii) any Power Plant Fuel Costs (iii) the financing costs, fees and expenses of an Owner relating to the ownership and acquisition of its interest in the Owned Assets, (iv) Taxes based upon the net income of any Owner or individually assessed against any Owner's Ownership Ratio in the Owned Assets or Ownership Ratio in respect of the Net Available Output of the Power Plant or from which any Owner is exempt, and (v) Costs of Capital Additions.

"Demand" has the meaning specified in Section 9.02(c)(1).

"DEMc" means Duke Energy McClain, LLC, a Delaware limited liability company and former owner of an undivided interest in the Power Plant.

"Effective Date" has the meaning given to that term in Section 7.01.

"Elective Capital Additions" means Capital Additions that are not required (i) to operate the Power Plant in accordance with Prudent Operating Practices, (ii) to assure design capability and reliability of the Power Plant, or (iii) by any Governmental Authority or pursuant to any Applicable Law.

"Energy" means electric energy or electricity.

"Executive Committee" means the Executive Committee established pursuant to Section 3.03(a).

"Facility Operating Agreement" means the Amended and Restated Facility Operating Agreement among the Owners and the Operator, as amended from time to time. As provided in Section 3.01(b), as of the date hereof the Facility Operating Agreement shall be between OMPA and OG&E and shall be in the form of Exhibit A.

"Fuel Agreement" means the Contract for Sale and Purchase of Natural Gas dated the date hereof by and between OG&E and OMPA, as amended from time to time.

"Force Majeure" has the meaning given to it in Section 9.03(a).

"Governmental Authority" means any court, tribunal, arbitrator, authority, agency, commission, official or other instrumentality of the United States, any foreign country or any domestic or foreign state, county, city or other political subdivision or similar governing entity, other, in any case, than OMPA.

"Initiating Owner" has the meaning given to it in Section 3.03(i)(1).

"Interests" has the meaning given to it in Section 3.03(i).

"LTSA" means that certain Long Term Service Agreement, dated as of December 29, 1999, by and between OG&E and General Electric International, Inc. , as such agreement has been or may be amended, supplemented, restated or otherwise modified.

"Majority of Members" means Members representing Owners holding in the aggregate more than 50% of the aggregate Ownership Ratios.

"Market Dispatch Sale Agreement" means the OG&E/OMPA Market Dispatch Sale Agreement dated the date hereof by and between OG&E and OMPA, as amended from time to time.

"Member" has the meaning given to it in Section 3.03(b).

"Net Available Output" means the net amount of Capacity available from and Energy, Ancillary Services and all other related products of the Power Plant that can be sold or

purchased, produced by the Power Plant from time to time under the operating conditions then existing, including periods when some or all of the Power Plant may be inoperable, after station use.

"Net Generating Capability" means the total amount of Energy which the Power Plant is capable of generating, with due allowance being made for legal, regulatory and physical constraints then existing, less the amount used in the production thereof.

"NRG McClain" has the meaning given in the recitals to this Agreement.

"Offer Period" has the meaning given to it in Section 3.03(i)(1).

"Operating Budget" has the meaning given to it in Section 3.04(b).

"Operating & Maintenance Agreements" means, collectively, the Facility Operating Agreement and the Transmission O&M Agreement.

"Operator" has the meaning given to it in Section 3.01(b). As of the date hereof, the Operator is OG&E.

"Original Agreement" has the meaning given in the recitals to this Agreement.

"Owned Assets" means the assets comprising the Power Plant and which are owned by the Parties as tenants in common.

"Owners" means OG&E and OMPA and any other Person that acquires an interest in the Owned Assets in accordance with the terms of this Agreement.

"Ownership Ratio" has the meaning given to it in Section 2.01.

"Permitted Liens" means any Permitted Liens under the Power Plant Asset Purchase Agreement, provided, however, that clause (j) of such definition may include Liens (as defined in the Power Plant Asset Purchase Agreement), imperfections or failures of title of the types described in clauses (a) through (i) thereof without regard to any contest.

"Person" means any natural person, corporation, general partnership, limited partnership, proprietorship, limited liability company, other business organization, trust, union, association or Governmental Authority.

"Power Plant" has the meaning given to it in the recitals hereto.

"Power Plant Asset Purchase Agreement" has the meaning given to it in the recitals hereto.

"Power Plant Fuel Costs" means all costs for supply, transportation and storage of fuel used in the Power Plant.

"Prudent Operating Practices" means the practices, methods and acts (including but not limited to the generally accepted practices, methods and acts engaged in or approved by

the operators of similar electric generating facilities) which at the time such practice, method or act is employed, and in the exercise of reasonable judgment in light of the facts known at such time, would be expected to accomplish the desired result in a workmanlike manner, consistent with (a) Applicable Laws and governmental requirements, and (b) reliability, safety and environmental protection. "Prudent Operating Practices" shall not require the use of the optimum practice, method or act, but only requires the use of acceptable practices, methods or acts generally accepted in the United States in performing obligations in accordance with Prudent Operating Practices.

"Receiving Owner" has the meaning given to that term in Section 3.03(i)(1).

"Resolution Deadline" has the meaning given to that term in Section 3.03(i).

"Rules" has the meaning specified in Section 9.02(c)(1).

"Schedule and Exchange Agreement" means the Schedule and Exchange Agreement dated the date hereof by and between OG&E and OMPA, as amended from time to time.

"Supermajority of Members" means Members representing Owners holding in the aggregate more than 85% of aggregate Ownership Ratios.

"Taking" means the taking of any of the Power Plant as a result of the exercise of the power of eminent domain or condemnation for public or quasi-public use or the sale or conveyance of any of the Power Plant under the threat of condemnation.

"Taxes" means all taxes, charges, fees, levies or other assessments imposed by any United States federal, state or local or foreign taxing authority, including but not limited to, income, excise, property, sales, transfer, franchise, payroll, withholding, social security or other taxes, including any interest, penalties or additions attributable thereto.

"Term" means the term of this Agreement as defined in Section 7.01.

"Termination Date" has the meaning given to it in Section 7.01.

"Transmission O&M Agreement" means the Operating and Maintenance Agreement for the Transmission Assets of the McClain Generating Facility by and between OMPA and OG&E dated as of August 25, 2003, as amended from time to time.

"Variable Operating Maintenance Share" means $2 per megawatt hours (MWh) of Energy. Except as otherwise agreed to, the Variable Operating Maintenance Share is payable by any Owner that schedules any unscheduled Energy of another Owner to such Owner with respect to such Energy.

1.02 Interpretations. In this Agreement, unless clear contrary intention appears: (i) the singular number includes the plural number and vice versa; (ii) reference to any Person includes such Person's successors and assigns but, if applicable, only if such successors and assigns are permitted by this Agreement, and reference to a Person in a particular capacity excludes such

Person in any other capacity; (iii) reference to any gender includes each other gender; (iv) reference to any agreement (including this Agreement), document or instrument means such agreement, document or instrument as amended or modified and in effect from time to time in accordance with the terms thereof and, if applicable, the terms hereof, (v) reference to any Article, Section, Schedule or Exhibit means such Article, Section, Schedule or Exhibit to this Agreement, and references in any Article, Section, Schedule, Exhibit or definition to any clause means such clause of such Article, Section, Schedule, Exhibit or definition, (vi) "hereunder," "hereof," "hereto," "herein" and words of similar import are reference to this Agreement as a whole and not to any particular Section or other provision hereof; (vii) relative to the determination of any period of time, "from" means "from and including," "to" means "to but excluding" and "through" means "through and including;" (viii) "including" (and with correlative meaning "include") means including without limiting the generality of any description preceding such term; and (ix) reference to any law (including statutes and ordinances) means such law as amended, modified, codified or reenacted, in whole or in part, and in effect from time to time, including rules and regulations promulgated thereunder.

ARTICLE II

OWNERSHIP RATIOS

2.01 Ownership Ratios.

(a) The Owners own the Owned Assets as tenants in common with each owning, as of the Effective Date, undivided interests in the following percentages:

OMPA: 23.0%

OG&E: 77.0%

Each Owner's undivided interest in the Owned Assets, as it may change from time to time as provided herein, is referred to herein as its "Ownership Ratio." Ownership Ratios may be modified only as provided in Sections 2.04, 6.01(b) and 8.02(a).

(b) Owners shall have the right to schedule and receive the Net Available Output of the Power Plant in the same percentages as their Ownership Ratios, subject to the Schedule and Exchange Agreement.

2.02 Changes in Ratios. Any changes in Ownership Ratios shall be given effect as provided pursuant to the terms and conditions of this Agreement without any further act, except such regulatory approval(s) as may be required.

2.03 Waiver of Partition. The Owners expressly waive any right of partition with respect to the Owned Assets, whether by partition in kind or sale and division of the proceeds thereof, until the end of Power Plant operations as described in Section 6.02.

2.04 Admission of New Owner. No Person shall succeed to or acquire the rights provided to Owners under this Agreement unless and to the extent that (i) the assignment or transfer pursuant to which it acquired its Interests in the Power Plant is valid under the terms of

this Agreement and (ii) it becomes a party to this Agreement either by execution of this Agreement or by a written agreement acceptable to a Majority of Members to be bound by all of the terms and conditions hereof. For the avoidance of doubt, OMPA hereby acknowledges as valid and consents to the assignment and transfer by NRG McClain to OG&E of NRG McClain's interest in and rights under the Original Agreement and 77% undivided interest in the Owned Assets.

ARTICLE III

OPERATION AND PAYMENT OF COSTS

3.01 Operations of the Power Plant. The Owners collectively agree that the Power Plant, including each Owner's respective ownership interests in the Owned Assets, shall be operated together pursuant to this Agreement as follows:

(a) All decisions in respect of operating, maintaining, administering contracts relating to improving and adding capital improvements to the Power Plant are hereby delegated to the Executive Committee established pursuant to Section 3.03(a) hereof.

(b) Unless otherwise agreed by the Executive Committee pursuant to Section 3.03(g) hereof the day to day operation and maintenance of the Power Plant will be performed by OG&E as operator (the "Operator"). The rights and duties of the Operator shall be as set forth in the Operating and Maintenance Agreements as in effect from time to time. The Owners acknowledge that DEMc as operator under a predecessor Facility Operating Agreement subcontracted certain matters relating to the major maintenance and repair of the Power Plant to General Electric International, Inc. pursuant to the LTSA that will be assigned to OG&E as of the Power Plant Closing and that OG&E is in the process of negotiating amendments to the LTSA. OMPA hereby approves an amended LTSA to the extent that such amended LTSA does provide for terms that are provided for under the Memorandum of Understanding dated as of October 26, 2003 between General Electric International, Inc. and OG&E; provided, however, that any additional changes to the LTSA shall be approved by the Executive Committee pursuant to Section 3.03(f).

3.02 [Intentionally omitted.]

3.03 Executive Committee.

(a) Establishment of Executive Committee. The Owners hereby establish the Executive Committee to carry out such functions as may be delegated to it by the Owners as set forth herein. In addition to the rights set forth in Section 3.03(d), the Executive Committee shall have the power to establish policies and procedures for the operation and maintenance of the Owned Assets review and approve operating budgets, management compensation, specifications, annual schedules, capital budgets and similar major decision matters, and generally provide such guidance and direction as is needed to operate and maintain the Owned Assets. The Operator shall report to the Executive Committee and shall be responsible for the day-to-day oversight and coordination of matters relating to the operation and maintenance of the Power Plant and such other matters as may be delegated to the Operator by the Executive Committee.

(b) Composition of Executive Committee. Each Owner shall appoint one representative to the Executive Committee (each such representative, a "Member"). Each Member shall have a single vote equal to the Ownership Ratio of the Owner that appointed such Member. Each Member on the Executive Committee shall hold office until death, resignation or removal at the pleasure of the Owner that appointed such Member to the Executive Committee. If a vacancy occurs on the Executive Committee, the Owner that appointed such vacating Member shall appoint a successor. Each Owner may also designate an alternate who shall be authorized to act in the absence of the Executive Committee representative or representatives for whom he or she is an alternate. Each alternate shall also hold office until death, resignation or removal at the pleasure of the appointing Owner. The initial Members and alternates on the Executive Committee and their successors shall be appointed by the respective Owners by written notice to the other Owners. No Executive Committee Member or alternate shall be entitled to compensation or reimbursement of expenses from the Owners for attendance at such meetings. Owners also may vote by one or more other proxies authorized by a written appointment of proxy signed by the Owner or by an Owner's duly authorized attorney-in-fact and delivered to the Executive Committee for inclusion in the minutes or filing with the Executive Committee's records. In the event that any Owner ceases to be an Owner for any reason whatsoever, the Member on the Executive Committee appointed by such Owner shall immediately cease to be a Member thereof.

(c) Executive Committee Meetings. The Executive Committee shall hold regular meetings quarterly on the date established from time to time by the Executive Committee. Between regular meetings, the chairman of the Executive Committee may call special meetings upon three days' written notice to all Members, or upon such shorter telephonic notices the chairman determines is appropriate to respond to emergency situations. The Executive Committee shall keep written minutes of its meetings. Any action which may be taken at a meeting of the Executive Committee may be taken without a meeting by individual action taken in writing by Members of the Executive Committee representing sufficient Ownership Ratios to approve such action. Participation by conference telephone where all participants can hear one another shall constitute participation in person.

(d) Powers and Duties of Executive Committee. Subject to the terms and conditions of this Agreement and the Facility Operating Agreement, the Executive Committee shall have full power and complete authority to make all decisions and manage and direct all aspects of the operation and maintenance of the Power Plant, including with respect to enforcement of any contractual rights in respect of the Power Plant, appointment of the Operator, entering into amendments or modifications to the Facility Operating Agreement and agreeing to the terms and conditions of any similar agreements with any replacement Operator. Subject to the provisions of Section 3.03(g), the Executive Committee may delegate such of its authorities and responsibilities to an Owner, or officer or employee of any Owner, or other party as the Executive Committee may elect, including, without limitation, the Operator. The Owners hereby consent to the exercise by such Persons of the powers contemplated by this Agreement and to the employment, when and if the same is deemed necessary or advisable, of such brokers, agents, accountants, attorneys and other advisors as such Persons may determine to be appropriate for the management of the Owned Assets.

(e) Powers and Duties of Chairman. The chairman of the Executive Committee shall be elected by the Executive Committee and shall be responsible for (i) providing notice of meetings to all Members, (ii) preparing an agenda for all meetings in consultation with the Operator, (iii) setting the times for approval of certain actions or decisions, which shall be not less than three days except in case of matters which in the chairman's judgment require emergency action or decision, (iv) presiding over all meetings and directing the order of business and procedures thereof; (v) arranging for the keeping of the minutes of all meetings and the distribution thereof to all Members and (vi) taking such other action with respect to meetings of the Executive Committee as may seem necessary or appropriate in the judgment of the chairman. The chairman of the Executive Committee may be removed and a new chairman of the Executive Committee may be appointed by the vote of a Majority of Members.

(f) Voting. Each Executive Committee Member shall vote that Owner's entire Ownership Ratio of the Owner which appointed such Member on any matter to be decided by the Executive Committee. Except as otherwise provided in Section 3.03(g), below, decisions of the Executive Committee shall be made by the approval of a Majority of Members. Matters not disapproved by a Member of the Executive Committee within the time after submission specified in the submittal, which shall not be less than specified in this Agreement (or if no time is specified in this Agreement, then within seven (7) calendar days) shall be deemed approved by such Member. No Member shall disapprove (i) matters which were submitted to the Executive Committee pursuant to the terms of this Agreement and not disapproved within the time allowed, (ii) items found by an arbitrator pursuant to the dispute resolution provisions hereof to be or have been consistent with Prudent Operating Practices, (iii) items where costs were borne solely by another Owner or the Operator individually, or (iv) items recommended by the chairman or the Operator having a total cost to all Owners in the aggregate of less than $70,000.

(g) Supermajority Matters. The following matters when submitted to the Executive Committee shall require the approval of a Supermajority of Members:

(i) except to the extent that the then current Operating & Maintenance Agreements otherwise provide, (A) the termination of such Operating & Maintenance Agreements, (B) any material amendment to any of the Operating & Maintenance Agreements, or (C) the approval of new Operating & Maintenance Agreements or the replacement or appointment of the Operator (such approval not to be unreasonably withheld or delayed by any Owner, which approval of a proposed replacement Operator shall not be withheld by any Owner if such replacement Operator is a qualified operator of gas-fired combined cycle facilities with similar technology as the Power Plant);

(ii) Elective Capital Additions requiring a total cost to all Owners in the aggregate in excess of $10,000,000; provided, however, that approval of a Supermajority of Members will not be required with respect to any such Elective Capital Additions if (A) the Owner(s) consenting to the Elective Capital Additions agree to bear all Costs of Capital Additions with respect thereto and (B) the carrying out of such Elective Capital Additions will not unreasonably interfere with the ability of non-consenting Owner(s) to obtain its or their

Ownership Ratio of Net Available Output; provided, further, that all Elective Capital Additions requiring a total cost to all Owners in the aggregate of less or equal to $10,000,000 and all other Elective Capital Additions that have been approved by a Supermajority of Members in accordance with this Section 3.03(g) shall be deemed Capital Additions for purposes of this Agreement;

(iii) a decision to settle Third Party Claims where the uninsured portion of any such claim exceeds $10,000,000;

(iv) a decision to end Power Plant operations as provided in Section 6.02; and

(v) proposals to change any of the terms of this Section 3.03(g).

(h) Notwithstanding the foregoing, for so long as OMPA is an Owner and any bonds or other securities, the interest on which is excluded from gross income for federal income tax purposes, and which were issued or are to be issued to finance or refinance the acquisition of OMPA's undivided interest in the Power Plant, remain outstanding, no Facility Operating Agreement shall include any provision that OMPA determines, on the basis of an opinion of counsel, could adversely affect the exclusion from gross income, for federal income tax purposes, of the interest on such bonds or other securities issued or to be issued by OMPA in such financing or refinancing.

(i) Deadlock. In the event that (i) there are only two Owners (for purposes of this Section 3.03(i) a Person and all of its Affiliates shall be treated as a single Owner) or if there are more than two Owners, one Owner and its Affiliates has an Ownership Ratio of more than 50%, (ii) the Members representing such Owners disagree with respect to the resolution of any matter requiring the approval of a Supermajority of Members as provided in Section 3.03(g)(i) or Section 3.03(g)(ii) (but only if such Elective Capital Additions will benefit all Owners in proportion to their Ownership Ratios), and (iii) the respective senior management representatives of the Owners have not resolved such disagreement within thirty (30) days of a written notice from an Owner requesting such resolution ("Resolution Deadline"), then (A) the dispute resolution procedures of Section 9.02 hereof shall not apply to such disagreement (but will continue to apply with respect to any dispute concerning the application of this subsection (i) or the interpretation thereof), and (B) any Owner may, provided such Owner is not then a defaulting Owner hereunder, by written notice ("Buy-Sell Notice") to the other Owners within 15 days after the Resolution Deadline initiate the following procedure ("Buy-Sell Procedure") with respect to offers to buy and sell each Owner's respective interests in the Power Plant (the "Interests"). If no Owner initiates the Buy-Sell Procedure by timely delivery of a Buy-Sell Notice, the disagreement may be resolved pursuant to the dispute resolution procedures provided in this Agreement. Notwithstanding the foregoing, in the event of the disposition by OG&E of all, or substantially all, of its ownership interests in the Power Plant, any disagreement among the Owners as to the qualification of any replacement Operator proposed in connection with such disposition shall be subject to the dispute resolution procedures set forth in Section 9.02, rather than the Buy-Sell Procedure.

(1) Within 15 days of the date of delivery of the Buy-Sell Notice, the initiating Owner (the "Initiating Owner") shall submit to all of the other Owners (each, a

"Receiving Owner") an offer in writing which shall be an offer to purchase all of the Interests of the Receiving Owners for the price, per 1% of Ownership Ratio, set forth in the offer. Such offer shall be irrevocable for a period of 15 days from the date of submission to the Receiving Owners ("Offer Period").

(2) Prior to the end of the Offer Period, each Receiving Owner must either (A) accept in writing the Initiating Owner's offer, or (B) make a counteroffer (irrevocable for a period of 15 days from the date of submission thereof) to purchase all of the Interests of the other Owners for a price per 1% of Ownership Ratio that exceeds the offered price per 1% of Ownership Ratio by at least 5% of the offered price. If a Receiving Owner makes a counteroffer pursuant to this Section 3.03(i)(2), the counteroffer shall be treated as an offer made pursuant to Section 3.03(i)(1) hereof initiating a new Offer Period, the Owner making such counteroffer shall be treated as the Initiating Owner, and the Owners receiving the counteroffer shall be treated as, and have the rights of, the Receiving Owners pursuant to this Section 3.03(i)(2) to either accept the counteroffer or make a new counteroffer.

(3) Notwithstanding the foregoing, at any time prior to the end of any Offer Period, any Receiving Owner may terminate the Buy-Sell Procedure with respect to its Interest in the Power Plant by acquiescing in writing in all respects to the position of the then Initiating Owner with respect to the matter or matters then in dispute. If as a result of such acquiescence, such matter or matters are approved by a Supermajority of Members, the Buy-Sell Procedure shall be terminated in respect of all Owners and the matter or matters in question shall be deemed to have been approved by a Supermajority of Members. If such acquiescence does not result in the approval of such matter or matters by a Supermajority of Members, the Buy-Sell Procedure shall continue but the then Initiating Owner's offer shall not apply to the acquiescing Owner, which shall not be considered to be a Receiving Owner with respect to such offer.

(4) Failure by a Receiving Owner to accept an offer, make a conforming counteroffer or acquiesce in respect of the matter or matters then in dispute as provided herein by the end of an Offer Period shall constitute acceptance of the last conforming offer made. Within 30 days after acceptance in writing or the end of an Offer Period resulting in deemed acceptance of an offer by all of the Receiving Owners, the Owners shall enter into an asset purchase agreement with respect to the Interests being purchased which shall have customary terms and conditions mutually agreed to by the parties thereto and provided that (A) the purchase price shall be payable entirely in cash in immediately available funds as of the closing under such asset purchase agreement, (B) the Interests shall be free and clear of all liens and encumbrances (other than Permitted Liens), including, without limitation, any obligations in respect to the Capacity or Energy produced by the Power Plant, and (C) the termination of this Agreement and the Facility Operating Agreement shall be a condition precedent to the closing of such asset purchase agreement.

3.04 Payment of Expenses: Operating Budget.

(a) Except as provided in this Section 3.04(a), each Owner shall be fully and individually responsible for the timely payment of its Ownership Ratio of all Costs of Operation

(adjusted, to the extent applicable, for payments by Owner's of their Variable Operating Maintenance Share), all Costs of Capital Additions and, to the extent applicable, each Owner's Variable Operating Maintenance Share. Furthermore, each Owner shall be fully and individually responsible for the timely payment of its Power Plant Fuel Costs in accordance with the Fuel Agreement or pursuant to agreements individually entered into by such Owner for the supply, transportation and/or storage of fuel to be used on behalf of such Owner in the Power Plant. Notwithstanding the foregoing:

(1) If the then current Operating & Maintenance Agreements provide for the direct allocation of amounts payable thereunder to one or more of the Owners, the terms of the Operating & Maintenance Agreements shall control with respect to such amounts.

(2) Except as otherwise agreed to, costs payable hereunder or under the Operating & Maintenance Agreements shall include only actual costs without markup.

(3) Each Owner shall be fully and individually responsible for the payment of its own financing costs and Taxes whether arising in connection with this Agreement, the Power Plant or otherwise.

(4) OG&E will, upon the Power Plant Closing, make necessary and appropriate transmission system upgrades and improvements when OG&E deems necessary to the transmission system to accommodate the full capacity output of the Power Plant, and OG&E agrees that none of the costs and expenses associated with such additional transmission system upgrades and improvements shall be allocated to OMPA under the Operating & Maintenance Agreements. The transmission system upgrades and improvement shall inure to the benefit of all Owners in proportion to their respective Ownership Interests, but shall at all times be the property of OG&E and be subject to being included as part of subsequent Open Access Transmission Tariff charges to third parties, including OMPA. The transmission system upgrades and improvements are expected to be completed and in service at the end of eighteen (18) months following the Power Plant Closing.

(b) On or before October 1 of each year, commencing 2004, the Operator will provide to the Executive Committee a reasonable estimate of the operating budget (the "Budget Estimate") for the next year. On or before November 15 of each year, commencing 2004, the Executive Committee shall prepare (based on the Budget Estimate) and approve an operating budget (the "Operating Budget") for the next calendar year. The Operating Budget for calendar year 2004 shall be prepared and approved by the Executive Committee within 30 days after execution of this Agreement. The Operating Budget shall contain the Executive Committee's reasonable estimate of all costs and expenses incurred each month for the operation and maintenance of the Power Plant, including without limitation, estimated amounts payable under the Facility Operating Agreement, fuel costs and budgeted capital expenditures. The Executive Committee may amend the Operating Budget from time to time.

(c) Within fifteen days of receipt of an invoice therefor from the Operator, each Owner shall pay the Operator such Owner's Ownership Ratio of the actual Costs of

Operation and Costs of Capital Additions, provided, however, if such costs exceed any line item in the Operating Budget by more than 10%, no Owner shall be obligated to pay any such amount until such amount is approved by the Executive Committee by means of an amendment to the Operating Budget.

3.05 Claims Treated as Costs of Operation. Except as otherwise specifically provided herein, the Owners shall be responsible for any and all Claims of Persons who are not Owners arising from or related in any way to the Power Plant in proportion to their Ownership Ratio.

3.06 Books and Records. Operator shall keep, in conformity with all requirements of Law, proper books, records, accounts, ledgers, time cards, estimates, schedules, correspondence and other documents related to the Operator's performance of its obligations hereunder and amounts due to the Operator under any Facility Operating Agreement. During ordinary business hours and upon reasonable notice to Operator, each Owner may inspect, copy and audit such books and records. Operator agrees to keep such books and records for five years following their respective preparation (at which time it will be permitted to destroy such books and records in the ordinary course of business) and will furthermore keep any such books and records not previously destroyed in the ordinary course of business, for five years after the termination of this Agreement, and shall provide copies thereof to each Owner upon request, at such requesting Owner's expense. The acceptance, approval or payment by any Owner of the Operator's charges in complying with such request shall not operate as a waiver of such Owner's right to audit the Operator in accordance with this Section 3.06.

3.07 Fuel Supply. Each Owner is individually responsible for the supply, transfer and/or storage of fuel (including, without limitation, any imbalance services associated therewith) used or to be used in connection with operation of the Power Plant to produce Energy for the account of such Owner. Notwithstanding the previous sentence, simultaneously with the execution of this Agreement, OG&E and OMPA entered into the Fuel Agreement pursuant to which OG&E exclusively provides fuel and imbalance services to OMPA as of the effective date thereof, responsibility for which services shall automatically revert to OMPA upon termination of said Fuel Agreement.

ARTICLE IV

ALLOCATION AND SCHEDULING OF NET AVAILABLE OUTPUT

4.01 Allocation of Net Available Output

.

(a) Subject to the Schedule and Exchange Agreement, scheduling procedures hereof and the availability of the Power Plant, each Owner shall be entitled to schedule and take all or any part (in accordance with Exhibit B, II, C) hereto) of its Ownership Ratio of the Net Available Output of the Power Plant.

(b) Except as otherwise agreed to, each Owner shall be solely responsible for all costs, penalties or damages caused to the Operator if an Owner fails to make available the supply, transportation and/or storage of fuel required to meet such Owner's scheduled Net Available Output of the Power Plant, and if fuel is not actually received from other sources, such

Owner shall not be entitled to the scheduled Net Available Output of the Power Plant to which it would otherwise be entitled to the extent of such unavailability.

4.02 Scheduling of Net Available Output. The Owners shall schedule their entitlement to Net Available Output in accordance with the operating procedures set forth in Exhibit B hereto.

ARTICLE V

LIMITATION OF LIABILITY

5.01 Limitation of Liability. THE EXPRESS REMEDIES AND MEASURES OF DAMAGES PROVIDED FOR IN THIS AGREEMENT SHALL BE THE SOLE AND EXCLUSIVE REMEDIES FOR AN OWNER HEREUNDER AND ALL OTHER REMEDIES OR DAMAGES AT LAW OR IN EQUITY ARE WAIVED. IF NO REMEDY OR MEASURE OF DAMAGES IS EXPRESSLY HEREIN PROVIDED, AN OWNER MAY, SUBJECT TO THE LIMITATIONS OF THE NEXT SENTENCE HEREOF, RECOVER SUCH REMEDIES, INCLUDING DAMAGES AND FEES AND EXPENSES OF ATTORNEYS AS MAY BE AVAILABLE AT LAW OR EQUITY. NOTWITHSTANDING THE FOREGOING, HOWEVER, NO OWNER SHALL UNDER ANY CIRCUMSTANCES BE LIABLE FOR CONSEQUENTIAL, INCIDENTAL, PUNITIVE OR EXEMPLARY DAMAGES, WHETHER BY STATUTE, IN TORT OR CONTRACT OR OTHERWISE. THE LIMITATIONS HEREIN IMPOSED ON REMEDIES AND THE MEASURE OF DAMAGES SHALL BE WITHOUT REGARD TO THE CAUSE OR CAUSES RELATED THERETO, INCLUDING THE NEGLIGENCE OF ANY OWNER. TO THE EXTENT ANY DAMAGES REQUIRED TO BE PAID HEREUNDER ARE LIQUIDATED, THE OWNERS ACKNOWLEDGE THAT THE DAMAGES ARE DIFFICULT OR IMPOSSIBLE TO DETERMINE, OTHERWISE OBTAINING AN ADEQUATE REMEDY IS INCONVENIENT AND THE LIQUIDATED DAMAGES CONSTITUTE A REASONABLE APPROXIMATION OF THE HARM OR LOSS.

ARTICLE VI

DAMAGE TO POWER PLANT; END OF OPERATIONS

6.01 Damage to, or Condemnation of, the Power Plant.

(a) In the event that the Power Plant suffers damage resulting from causes other than ordinary wear, tear or deterioration, or to the extent any Taking affects the Power Plant, to the extent that the estimated uninsured or uncompensated cost of repair as determined by the Executive Committee, or, if a Majority of Members cannot agree within a period of six (6) months from the date of damage, as determined by the arbitrator pursuant to the dispute resolution provisions hereof; is less than or equal to $10 million, and if the Executive Committee does not determine that the operations of the Power Plant shall be ended pursuant to Section 6.02, the Executive Committee shall promptly cause the Operator to submit a revised Operating Budget and shall proceed to cause the repair of the Power Plant, and each Owner shall pay as budgeted, into a separate trust account, its Ownership Ratio of the estimated uninsured or uncompensated cost thereof.

(b) If the Power Plant suffers damage or a Taking to the extent that the estimated uninsured or uncompensated cost of repair exceeds $10 million as determined in accordance with Section 6.01(a) the Executive Committee shall, or, if a Majority of Members cannot agree within six (6) months from the date of damage, the arbitrator shall, determine the estimated value of the Power Plant as and when repaired. Thereafter, each Owner which, within a reasonable time to be determined by the Executive Committee, gives notice in writing to the other Owners of its desire that the Power Plant be repaired, shall, in the proportion that its Ownership Ratio bears to the total of the Ownership Ratio of all Owners giving such notice, pay into the separate trust account, as budgeted in a revised budget, all of the estimated uninsured or uncompensated cost of repair. If any Owner has given such a notice, the Ownership Ratio of each Owner which did not give such a notice shall, at the end of the reasonable time which was determined by the Executive Committee, be reduced to the extent determined by the following formula:

$$O2 = O1 \times \frac{V - (C - I)}{V}$$

where

V	=	Estimated value of the Power Plant as repaired
C	=	Estimated cost of repair
I	=	Estimated insurance or compensation proceeds, if any, inuring to the benefit of all Owners (shall not include insurance or compensation proceeds to which only individual Owners are entitled)
O1	=	Ownership Ratio prior to loss
O2	=	Reduced Ownership Ratio

At the same time, the amount of such reductions shall be added to the Ownership Ratio of the Owners giving such notice in the proportion that the Ownership Ratio of each bears to the total of the Ownership Ratios of all Owners giving such notice.

(c) If the Power Plant suffers damage to the extent that the estimated uninsured or uncompensated cost of repair as determined in Section 6.01(a) exceeds $10 million and no Owner gives the notice required by Section 6.01(b), the damaged Power Plant shall not be repaired. If portions of the Power Plant are still capable of economically generating electricity, then the Executive Committee shall cause the Operator to implement the procedures specified in Section 6.02 with respect to the damaged facilities only and continue to operate the remaining facilities. If no portion of the Power Plant is still capable of economically generating electricity, then the Executive Committee shall cause the Operator to end Power Plant operations pursuant to Section 6.02.

(d) In the case of repair of the Power Plant pursuant to Sections 6.01(a) or (b), all proceeds of insurance and condemnation awards shall first be applied to repair of the Power Plant, with any excess being distributed to the Owners in accordance with their Ownership Ratios.

6.02 End of Power Plant Operations. When the Power Plant can no longer be made capable, consistent with Prudent Operating Practices, of producing electricity or cannot obtain required permits, or when the Owners otherwise agree to end Power Plant operations by the approval of a Supermajority of Members, the Executive Committee shall cause the Operator to sell for removal all salable parts of the Power Plant to the highest bidder(s). Each Owner shall bear its Ownership Ratio of all costs of termination of Power Plant operations, including the costs of decommissioning, razing all structures and disposing of the debris and meeting all requirements of Applicable Law. Each Owner shall receive its Ownership Ratio of any proceeds resulting from the liquidation by the Operator of the Power Plant pursuant to this Section 6.02 only after the payment of all costs of termination of Power Plant operations, including payment of any expenses authorized by the Executive Committee.

6.03 Insurance.

(a) The Executive Committee shall establish the types, limits and deductibles of insurance purchased for the Power Plant by OG&E on behalf of the Owners, which insurance shall at a minimum provide the coverages set forth in Schedule 6.03 hereto or as required by law.

(b) Unless otherwise agreed by the Executive Committee, all insurance shall be for the benefit of all Owners in accordance with their Ownership Ratios. In the event that any Owner acquires separate insurance covering its interest in the Power Plant, such policies shall be appropriately endorsed to provide waivers of subrogation to OG&E and all other Owners in order to prevent subrogation or the holding of OG&E or any other Owners responsible for losses.

ARTICLE VII

TERM AND TERMINATION

7.01 Term. This Agreement shall become effective, and amend and restate and supercede in its entirety the Original Agreement, upon the Power Plant Closing (the "Effective Date"). The term of this Agreement ("Term") shall be from the Effective Date through the date of the end of Power Plant operations as provided in Section 6.02 or the date of any earlier termination of this Agreement by the mutual written agreement of the Owners (the "Termination Date"), provided that the Owners shall comply with any orders of any Governmental Authority with respect to any earlier termination and the costs of such compliance shall be borne by the Owners at that time in accordance with their Ownership Ratios.

7.02 Termination. This Agreement shall not be subject to termination by any party or Owner prior to the Termination Date except as expressly provided in Section 7.01. Each of the Owners, to the extent not prohibited by Applicable Law, waives all rights now or hereafter existing, conferred by statute, common law or otherwise to quit, terminate or surrender this Agreement, other than any rights or obligations which may have accrued to such Owner, or to which such Owner may have become subject, hereunder prior to such termination.

ARTICLE VIII

DEFAULT AND REMEDIES

8.01 Default.

(a) Upon failure of an Owner to make any payment when due, fulfill any covenant, or, except as excused by Force Majeure, perform any material obligation of an Owner herein, any other Owner may make written demand upon said Owner.

(b) If the failure of an Owner is to make a payment when due, such failure shall immediately constitute a default; provided that, for the first two times that written demand pursuant to Section 8.01(a) is made upon such Owner, such failure to make payment when due shall not constitute a default if such nonpayment is cured within 15 calendar days from the date of the demand pursuant to Section 8.01(a).

(c) If the failure of an Owner is to fulfill any covenant or to perform any other material obligation, and if such failure is not cured within 30 days from the date of such demand, it shall, at the expiration of such period, constitute a default.

(d) If an Owner in good faith disputes the existence or extent of a failure described in Section 8.01(a), it shall, within the applicable period given to it in Sections 8.01(b) or (c), nonetheless make such payment or perform such obligation under written protest directed to the Owners. Such dispute shall be resolved pursuant to the dispute resolution procedures provided for herein.

8.02 Remedies.

(a) If a default is limited to a failure of the defaulting Owner to make payments, the defaulting Owner's Ownership Ratio of Net Available Output may, subject to rights of the then non-defaulting Owner(s) under the Market Dispatch Agreement and the Schedule and Exchange Agreement, be sold during the period of default for the benefit of the defaulting Owner (to third parties or other Owner(s)) and the proceeds applied to the amounts owed by such Owner; provided that the non-defaulting Owner(s) shall have no obligation to engage in any such sales. Payments not made when due may be advanced by the other Owner(s) and, if so advanced, shall bear interest until paid at the prime rate of Citibank, N.A. (or its successor) plus 5% or the highest lawful rate, whichever is lower. If a payment default (including accrued interest thereon) has not been brought current by the defaulting Owner by the 90th day following the original due date of such amount, then, in lieu of receiving a cash payment from the defaulting Owner therefor, any non-defaulting Owner may, to the extent permitted by Applicable Law, elect by 30 days' prior written notice to the defaulting Owner to increase its respective Ownership Ratio (and the Ownership Ratio of the defaulting Owner shall be correspondingly reduced) according to the following formula:

$$\text{Increased Interest} = SI \times \frac{A}{TV}$$

where SI means the defaulting Owner's then current Ownership Ratio;

A means the aggregate amount then owed by such defaulting Owner; and

TV means the product of such defaulting Owner's then current Ownership Ratio multiplied by the weighted average of the purchase price paid by all Owners for their respective Ownership Ratio.

If more than one Owner elects to increase its Ownership Ratio in lieu of receiving a cash payment from the defaulting Owner, the increases shall be apportioned on a pro rata basis among the prior Ownership Ratios of the electing Owners. No Owner shall be required to elect to increase its Ownership Ratio in lieu of receiving a cash payment from a defaulting Owner hereunder.

(b) If a default involves the failure of a defaulting Owner to fulfill any covenant or to perform any other material obligation, the defaulting Owner's Ownership Ratio of Net Available Output may, subject to rights of the then non-defaulting Owner(s) under the Market Dispatch Agreement and the Schedule and

Exchange Agreement, be used or sold by the non-defaulting Owner(s) as it may in its sole discretion determine during the period of such default, and the value thereof, calculated as the Variable Cost of producing the Energy actually generated from such Net Available Output, shall be credited to any actual damages incurred by the non-defaulting Owner(s) as a result of such failure or non-performance; provided that the non-defaulting Owner(s) shall have no obligation to so use or sell the defaulting Owner's Ownership Ratio of Net Available Output.

(c) In addition to the rights granted in this Section 8.02, any non-defaulting Owner may seek injunctive relief, including specific performance, to enforce a defaulting Owner's obligation under this Agreement; provided that all claims to recover damages or payments on account of any default hereunder shall proceed pursuant to the dispute resolution procedures provided herein.

ARTICLE IX

MISCELLANEOUS

9.01 Governing Law. THIS AGREEMENT SHALL BE GOVERNED BY, AND CONSTRUED, INTERPRETED AND ENFORCED IN ACCORDANCE WITH, THE SUBSTANTIVE LAW OF THE STATE OF OKLAHOMA WITHOUT REFERENCE TO ANY PRINCIPLES OF CONFLICTS OF LAWS THEREOF.

9.02 Dispute Resolution; Arbitration.

(a) Any dispute or claims arising under this Agreement which cannot be resolved by the parties through negotiation by the parties' managers shall be referred to a panel consisting of a senior executive of each party, with authority to decide or resolve the matter in dispute, for review and resolution. Such senior executives shall attempt to meet and resolve the dispute within 30 days.

(b) If the parties are unable to resolve a dispute as provided in Section 9.02(a), each party has the right to (i) pursue any legal and/or equitable remedies in the District Court of Oklahoma County or such other court of proper jurisdiction or (ii) seek to arbitrate the dispute using the procedures specified in Section 9.02(c); which election shall be binding upon such party with respect to the dispute at issue.

(c) If so elected by a party and the other party agrees in writing, a dispute shall be arbitrated in accordance with the following procedures:

(1) At the request of either party upon written notice to that effect to the other party (a "Demand"), the dispute shall be finally settled by binding arbitration before a panel of three arbitrators in accordance with the Commercial Arbitration Rules (the "Rules") of the American Arbitration Association ("AAA") then in effect, except as modified herein. The Demand must include statements of the facts and circumstances surrounding the dispute, the legal obligation breached by the other party, the amount in controversy and the requested relief accompanied by all relevant documents supporting the Demand.

(2) Unless the parties otherwise agree, arbitration shall be held in the headquarters cities of the parties alternating locations between sessions or meetings with the arbitrator(s) and beginning, for each arbitrated dispute, with the headquarters city of the party not making the Demand. The arbitration shall be governed by the United States Arbitration Act, 9 U.S.C. §§ 1 et seq.

(3) Each party shall select one arbitrator within ten days of the receipt of the Demand, or if such party to the dispute fails to make such selection within ten days from the receipt of the Demand, the AAA shall make such appointment. The two arbitrators thus appointed shall select the third arbitrator, who shall act as the chairman of the panel. If the two arbitrators fail to agree on a third arbitrator within 30 days of the selection of the second arbitrator, the AAA shall make such appointment.

(4) The award shall be in writing (stating the award and the reasons therefor) and shall be final and binding upon the parties, and shall be the sole and exclusive remedy between the parties regarding any claims, counterclaims, issues, or accountings presented to the arbitral panel. The arbitral panel shall be authorized in its discretion to grant pre-award and post-award interest at commercial rates. Judgment upon any award may be entered in any court having jurisdiction. For purposes of a pre-arbitral injunction, pre-arbitral attachment or other order in aid of arbitration proceedings, the parties hereby agree to submit to the jurisdiction of the United States federal courts located in, and the local courts of, the State of Oklahoma. Each of the parties irrevocably waives, to the fullest extent permitted by law, any objection it may now or hereafter have to the jurisdiction of such courts or the laying of the venue of any such proceeding brought in such a court and any claim that any such proceeding brought in such a court has been brought in an inconvenient forum. Each of the parties hereby consents to service of process by registered mail at its address set forth herein and agrees that its submission to jurisdiction and its consent to service of process by mail is made for the express benefit of the other party.

(5) This Agreement and the rights and obligations of the parties shall remain in full force and effect pending the award in any arbitration proceeding hereunder.

(6) Unless otherwise ordered by the arbitrators, each party shall bear its own costs and fees, including attorneys' fees and expenses. The parties expressly agree that the arbitrators shall have no power to consider or award any form of damages barred by Section 5.01, or any other multiple or enhanced damages, whether statutory or common law.

(7) The parties, to the fullest extent permitted by law, hereby irrevocably waive and exclude any rights of application or appeal or rights to state a special case for the opinion of the courts or any other recourse to the court system other than to enforce the agreement to arbitrate pursuant to this Section 9.02(c) for attachment or other order in aid of arbitration proceedings or to enforce the award of the arbitral panel.

(8) During the pendency of any dispute, the parties shall continue to perform the obligations imposed upon them under this Agreement to the fullest extent possible, consistent with their positions in dispute.

9.03 Force Majeure.

(a) "Force Majeure" means an event not anticipated as of the Effective Date which is not within the reasonable control of the party (or in the case of third party obligations or facilities, the third party) claiming suspension (the "Claiming Party"), and which by the exercise of due diligence the Claiming Party is unable to overcome in a commercially reasonable manner or obtain or cause to be obtained a commercially reasonable substitute performance therefor. Events of Force Majeure include, but are not restricted to: wrongful or negligent acts of the other party; acts of God; fire, civil disturbance; labor dispute or labor shortages; strikes sabotage, action or restraint by court order or Governmental Authority (so long as the Claiming Party has not applied for or assisted in the application for, and has opposed where and to the extent reasonable, such action or restraint); and inability after diligent application to obtain or maintain required permits, licenses, zoning or other required approvals from any Governmental Authority or other third-party Person whose consent is required as a condition to a party's performance hereunder.

(b) Suspension. If a party is rendered unable by Force Majeure to carry out, in whole or in part, its obligations under this Agreement and such party gives written notice and full details of the event to the other party as soon as practicable after the occurrence of the event, then during the pendency of such Force Majeure but for no longer period, the obligations of the party affected by the event (other than the obligation to make payments then due or becoming due with respect to performance prior to the event) shall be suspended to the extent required. The party affected by the Force Majeure shall remedy the Force Majeure with all reasonable dispatch.

9.04 Restrictions on Assignments and Transfers. An Owner shall be entitled to assign or transfer all or any of its Interests in the Power Plant to any Person who becomes an Owner pursuant to Section 2.04 without restriction of any kind.

9.05 Attorneys' Fees and Litigation Expenses. In the event any action is commenced to recover damages or enforce any rights or obligations under this Agreement, then the prevailing party in such action shall be entitled to recover its attorney fees, including the reasonable fees of in-house counsel, expert fees, and all reasonable out-of-pocket expenses incurred in enforcing the prevailing party's rights under this Agreement, regardless of whether those fees, costs or expenses are otherwise recoverable as costs in the action, including all fees and expenses incurred in investigation and preparation of the action before it is filed and upon appeal.

9.06 Notices.

(a) Means of Notification. Unless this Agreement specifically requires otherwise, any notice, demand or request provided for in this Agreement, or served, given or made in connection with it, shall be in writing and shall be deemed properly served, given or made if delivered in person or sent by fax or sent by registered or certified mail, postage prepaid, or by a nationally recognized overnight courier service that provides a receipt of delivery, in each case, to the parties at the addresses specified below:

If to OMPA:

Oklahoma Municipal Power Authority

Street Address:
2300 East Second Street
Edmond, OK 73034

Post Office Address:
P.O. Box 1960
Edmond, OK 78083-1960

Facsimile No. (405) 359-1071
Attn: General Manager

with a copy to:

Oklahoma Municipal Power Authority

Street Address:
2300 East Second Street
Edmond, OK 73034

Post Office Address:
P.O. Box 1960
Edmond, OK 78083-1960

Facsimile No. (405) 359-1071
Attn: General Manager

If to OG&E:

Oklahoma Gas and Electric Company
PO Box 321

Oklahoma City, Oklahoma 73101-0321
Attention: Jack T. Coffman,
Senior Vice President, Power Supply
Facsimile No.: (405) 553-3198

with a copy to:

Jones Day
77 West Wacker Drive, Suite 3500
Chicago, Illinois 60601-1692
Attention: Peter D. Clarke
Facsimile No.: (312) 782-8585

(b) Effective Time. Notice given by personal delivery, mail or overnight courier pursuant to this Section 9.06 shall be effective upon physical receipt. Notice given by fax pursuant to this Section 9.06 shall be effective as of (i) the date of confirmed delivery if delivered before 5:00 p.m. (central prevailing time) on any business day, or (ii) the next succeeding business day if confirmed delivery is after 5:00 p.m. (central prevailing time) on any business day or during any non-business day.

9.07 Waivers. Except as otherwise provided herein, no provision of this Agreement may be waived except in writing. No failure by any party to exercise, and no delay in exercising, short of the statutory period, any right, power or remedy under this Agreement shall operate as a waiver thereof. Any waiver at any time by a party of its right with respect to a default under this Agreement, or with respect to any other matter arising in connection therewith, shall not be deemed a waiver with respect to any subsequent default or matter.

9.08 No Reliance. Each party acknowledges that in entering into this Agreement, it has not relied on any statement, representation or promise of the other party or any other Person except as expressly stated in this Agreement.

9.09 Assumption of Risk. In entering into this Agreement, each of the parties assumes the risk of any mistake of fact or law, and if either or both of the parties should subsequently discover that any understanding of the facts or the law was incorrect, neither of the parties shall be entitled to, nor shall attempt to, set aside this Agreement or any portion thereof.

9.10 Waiver of Defenses. Upon the execution of this Agreement, the parties release each other from any and all claims relating to the formation and negotiation of this Agreement, including, but not limited to reformation, rescission, mistake of fact, or mistake of law. The parties further agree that they waive and will not raise in any court, administrative body or other tribunal any claim in avoidance of or defense to the enforcement of this Agreement other than the express conditions given to it in this Agreement.

9.11 No Third-Party Beneficiaries. None of the promises, rights or obligations contained in this Agreement shall inure to the benefit of any Person not a party to this Agreement; and no action may be commenced or prosecuted against any party by any third party claiming to be a third-party beneficiary of this Agreement or the transactions contemplated hereby.

9.12 Severability. If any provision of this Agreement is held to be illegal, invalid or unenforceable under any present or future law, and if the rights or obligations of any party hereto under this Agreement will not be materially and adversely affected thereby, (i) such provision will be fully severable, (ii) this Agreement shall be construed and enforced as if such illegal, invalid or unenforceable provision had never comprised a part hereof, (iii) the remaining provisions of this Agreement shall remain in full force and effect and will not be affected by the illegal, invalid or unenforceable provision or by its severance herefrom and (iv) in lieu of such illegal, invalid or unenforceable provision, there shall be added automatically as a part of this Agreement a legal, valid and enforceable provision as similar in terms to such illegal, invalid or unenforceable provision as may be possible.

9.13 Independent Counsel. The parties acknowledge that they have been represented by independent counsel in connection with this Agreement, they fully understand the terms of this Agreement, and they voluntarily agree to those terms for the purposes of making a full compromise and settlement of the subject matter of this Agreement.

9.14 Further Assurances. Each party shall promptly and with all due diligence take all necessary action in aid of obtaining all regulatory approvals, licenses and permits necessary to carry out its obligations under this Agreement. Each party shall, from time-to-time on request, execute deeds, bills of sale and whatever other documents that may be necessary in addition to this Agreement to evidence title.

9.15 No Partnership. Nothing in this Agreement shall create a partnership, joint venture, association or a trust. The parties shall affirmatively elect not to apply the provisions of Subchapter K of the Internal Revenue Code of 1986. Each party shall severally bear its respective share of all obligations and liabilities of the Power Plant as it arises. No Party shall have a right or power to bind any other party without its written consent, except as provided in this Agreement. IN THEIR RELATIONS WITH EACH OTHER UNDER THIS AGREEMENT, THE PARTIES SHALL NOT BE CONSIDERED FIDUCIARIES OR TO HAVE ESTABLISHED A CONFIDENTIAL RELATIONSHIP, BUT RATHER SHALL BE FREE TO ACT ON AN ARM'S LENGTH BASIS IN ACCORDANCE WITH THEIR OWN RESPECTIVE SELF-INTEREST, SUBJECT, HOWEVER, TO THE OBLIGATIONS OF THE OWNERS TO ACT IN GOOD FAITH IN THEIR DEALINGS WITH EACH OTHER WITH RESPECT TO ACTIVITIES HEREUNDER. NO OWNER NOR ANY AFFILIATE OF ANY OWNER, BY REASON OF SUCH OWNER'S INTEREST IN THE POWER PLANT OR APPOINTMENT OF A REPRESENTATIVE OF SUCH OWNER AS A MEMBER OF THE EXECUTIVE COMMITTEE, SHALL BE PRECLUDED FROM ENGAGING IN ANY ACTIVITIES SIMILAR TO THOSE TO BE CONDUCTED BY THE OTHER OWNERS IN RESPECT OF THE POWER PLANT OR ANY ACTIVITIES INCIDENTAL OR RELATED THERETO IN THE UNITED STATES OF AMERICA, MEXICO, OR ANYWHERE ELSE, NOR SHALL ANY OWNER OR ANY AFFILIATE OF ANY OWNER HAVE ANY OBLIGATION, BY REASON OF SUCH OWNER'S INTEREST IN THE POWER PLANT OR APPOINTMENT OF A REPRESENTATIVE OF SUCH OWNER AS A MEMBER OF THE EXECUTIVE COMMITTEE, TO MAKE AVAILABLE TO ANY OTHER PERSON ANY OTHER OPPORTUNITY THAT SUCH OWNER OR ANY OF ITS AFFILIATES MAY HAVE TO DEVELOP, CONSTRUCT, OWN, OPERATE, MAINTAIN OR FINANCE ANY OTHER PROJECT OF ANY KIND OR NATURE, INCLUDING, WITHOUT LIMITATION, ANY POWER PLANT PROJECT.

9.16 Ancillary Services. To the extent the Power Plant is used or may be used to generate Ancillary Services or related products from time to time, the Owners shall negotiate in good faith in an attempt to agree, consistent with their respective Ownership Ratio, on an equitable allocation of the costs and benefits, to account for such Ancillary Services or related products.

9.17 Access. Each party and its designees shall have the right to go upon and into the Power Plant at any time, subject to the necessity of efficient and safe construction and operation

of the Power Plant, but the Operator alone shall have possession and control of the Power Plant for and on behalf of all of the Owners.

9.18 Adjustments. For purpose of determining the responsibilities with respect to any contractual obligations between OMPA and NRG McClain under the Original Agreement outstanding as of the Power Plant Closing, OG&E and OMPA agree that in accordance with the Power Plant Purchase Agreement, OG&E will be responsible for the payment of all outstanding contractual obligations of NRG McClain owed to OMPA under the Original Agreement, if any, provided, however, that OG&E will not be liable to OMPA (and therefore NRG McClain will continue to be liable) with respect to any liabilities resulting out of the breach of, or a default under, the Original Agreement. Furthermore, all accounts payable currently owed by OMPA to NRG McClain under the Original Agreement, to the extent resulting from operation of the Power Plant prior to the Power Plant Closing, remain payable to NRG McClain. For purpose of clarification, this provision is strictly limited to contractual obligations under the Original Agreement and OG&E and OMPA agree that it does not create any obligations or liabilities of OG&E originated under the Original Agreement for claims based in tort, equity or otherwise.

9.19 Entire Agreement. This Agreement, together with the Operating & Maintenance Agreements, the Fuel Agreement, the Schedule and Exchange Agreement, the Market Dispatch Agreement and the Service Agreement For Power Sales Between OMPA and OG&E, constitute the complete and entire expression of agreements between the parties and supersede all prior and contemporaneous offers, promises, representations, negotiations, discussions, and communications, whether written or oral, including that certain Memorandum of Understanding re the subject matter of this Agreement between OMPA and OG&E dated September 15, 2003, all of which may have been made in connection with the subject matter of this Agreement, including, in each case, all schedules and exhibits thereto. Any such representations or claims are hereby disclaimed. This Agreement may be signed in counterparts.

[Remainder of page intentionally blank.]

IN WITNESS WHEREOF, the parties have executed this Agreement as of the date first above written.

OKLAHOMA MUNICIPAL POWER AUTHORITY

By: /s/ Charles Lamb

Name: Charles Lamb
Title: Chair, OMPA Board of Directors

Attest:

By: /s/ Roland Dawson

Name: Roland Dawson
Title: Assistant Secretary

OKLAHOMA GAS AND ELECTRIC COMPANY

By: /s/ Jack T. Coffman

Name: Jack T. Coffman
Title: Senior Vice President, Power Supply

Attest:

By:

Name:
Title:

Exhibit A

to

Amended and Restated Ownership and Operation Agreement

Amended and Restated Facility Operating Agreement

[Attached.]

Exhibit B

To
Ownership and Operation Agreement

Operating Procedures

I. Scheduling and Operational Notifications Contacts:

OG&E		OMPA	
Day Ahead	(405) 553-2116	Operations	(405) 340-8313
Hourly	(405) 553-2116	Backup	(405) 340-5047
		Ponca City Power Plant	(580) 763-8048

OMPA and OG&E will provide each other with full contact lists from time to time.

II. Daily Dispatching Procedure

A) Prior to 0800 central prevailing time on the business day (Weekends and Monday deliveries will require notification by the Friday preceding the date power is taken; NERC holidays or the next day after a holiday will require notification by the first business day preceding a holiday) prior to energy delivery, OG&E shall advise OMPA (i) what OMPA's Ownership Ratio of the Net Available Output is expected to be, (ii) whether OG&E will exercise its rights under the Schedule and Exchange Agreement and (iii) whether OG&E expects to run the Power Plant or not. If OG&E's preliminary decision is not to run the plant, OMPA and OG&E shall agree on a preliminary dispatch cost of the plant. The preliminary dispatch cost will be calculated using an estimated gas cost, and estimated heat rate of 7,500 Btu/kwh, and an operation and maintenance cost of $2.00/MWh. OMPA shall use the mutually agreed estimated cost in making its unit commitment decisions for the day in question.

B) Prior to 0830 central prevailing time on the business day (Weekends and Monday deliveries will require notification by the Friday preceding the date power is taken; NERC holidays or the next day after a holiday will require notification by the first business day preceding a holiday) prior to energy delivery, OMPA shall provide OG&E with a preliminary schedule of energy requirements which will include: quantity, time and any delivery point requirements.

C) If OG&E decides not to dispatch the Power Plant, it will notify OMPA and its designated fuel supplier (if other than OG&E) prior to 0830 central prevailing time on the day prior to energy delivery. In such event, OG&E shall, at the request of OMPA, sell power to OMPA pursuant to the Market Dispatch Sale Agreement under the OG&E market-based rate tariff under the rates, terms and conditions agreed to thereunder.

D) By 1130, central prevailing time on the business day prior to energy delivery, OG&E will provide OMPA with a written confirmation of OMPA's schedule which will include: Quantity, time and anticipated delivery points.

E) By 1130 central prevailing time on the business day prior to Energy delivery from the Power Plant, OG&E will provide OMPA and its designated fuel supplier (if other than OG&E) with a written confirmation of OMPA's fuel nomination which will include: Quantity and time of delivery.

III. Restart

If OG&E provides power from alternate energy sources and decides to restart the Power Plant after the dispatch notification time period:

A) OG&E will notify OMPA and its designated fuel supplier (if other than OG&E) that it has elected to restart the Power Plant.

B) If energy delivery from alternate resources is in progress, OG&E will have full rights to the ramp energy (the energy produced from the time start up commences until the earlier of (1) the time that OMPA's pro rata share of the Energy produced is equal to the replacement Energy, or (2) the time that the Power Plant reaches its then available capacity as set forth in a written notice from OG&E to OMPA and its designated fuel supplier.

C) OG&E will notify OMPA and its designated fuel supplier (if other than OG&E) of resource changes at the occurrence of the earlier of (1) the time that OMPA's pro rata share of the Energy produced is equal to the replacement Energy, or (2) the time that the Power Plant reaches its then available capacity as set forth in a written notice from OG&E to OMPA and its designated fuel supplier (if other than OG&E).

IV. Intraday Changes

A) If the Power Plant is on-line:

1) Intraday changes to the schedule will be allowed provided that notification is made at least one (1) hour prior to the implementation of the schedule change. OMPA cannot request a change in schedule that

will require the Power Plant to run outside prudent operating parameters, such as ramp rate and minimum operating load.

B) If OMPA is being served from alternate energy sources and the Power Plant is not on-line;

1) No intraday changes will be allowed, except by mutual agreement.

2) OMPA can elect to market excess energy on a real time basis.

C) If OMPA is being served from alternate energy sources and the Power Plant is on-line due to a restart:

1) OMPA will not be allowed to reduce the scheduled quantities or change the scheduled delivery point, except by mutual agreement.

2) OMPA can elect to market energy on a real time basis.

3) If OMPA is receiving less than its Ownership Ratio equivalent of the Power Plant's output from an alternate source, it can request additional energy up to a total delivered energy amount equivalent to its Ownership Ratio equivalent of the Power Plant's output.

4) If OMPA is receiving its Ownership Ratio equivalent of the Power Plant's output from an alternate energy source, it can elect to purchase energy from the Power Plant at the prevailing market price provided that notification is made at least one (1) hour prior to the implementation of the schedule change.

D) In the event that the Power Plant were to experience a transient event which results in a schedule curtailment, OG&E will notify OMPA and its designated fuel supplier (if other than OG&E) within fifteen minutes after the event occurs.

Schedule 6.03

to the Ownership and Operation Agreement

Insurance Coverages**

All Risk Property

Limits: Replacement Cost

Deductibles:

Per occurrence Property Damage: $200,000

Description of Coverage: "All Risks" of direct physical loss or damage

Excess Liability

Limits: $130,000,000

Deductible: $50,000

Description of Coverage: "Claims First Made" with payments on an indemnification basis per Aegis Form 8100 (1/98)

** Insurance coverages and deductibles based on current OG&E policies. Deductibles subject to change due to market conditions.

Exhibit 12.01

OGE Energy Corp.
S E C Method of
Ratio of Earnings to Fixed Charges

	Year Ended Dec 31, 1999	Year Ended Dec 31, 2000	Year Ended Dec 31, 2001	Year Ended Dec 31, 2002	Year Ended Dec 31, 2003
Earnings:					
Income from continuing operations	$ 139,962,231	$ 133,854,031	$ 93,879,245	$ 80,920,627	$ 135,568,239

Add Income Taxes	86,203,529	72,047,027	52,885,079	44,578,932	73,670,562
Add Fixed Charges	105,347,270	139,931,555	132,199,580	115,552,863	102,194,363
Subtotal	331,513,030	345,832,613	278,963,904	241,052,422	311,433,164
Subtract:					
Allowance for funds used during construction	719,576	2,229,277	707,822	905,189	538,624
Minority interest - NOARK	1,640,086	1,243,067	953,181	134,579	(1,376,897)
Total Earnings	329,153,368	342,360,269	277,302,901	240,012,654	312,271,437
Fixed Charges:					
Long-term debt interest expense	64,084,862	118,720,004	115,481,869	103,492,446	92,489,615
Other interest expense	36,891,106	16,173,031	12,462,336	8,250,174	6,045,733
Calculated interest on leased property	4,371,302	5,038,520	4,255,375	3,810,243	3,659,015
Total Fixed Charges	$ 105,347,270	$ 139,931,555	$ 132,199,580	$ 115,552,863	$ 102,194,363
Ratio of Earnings to Fixed Charges	3.12	2.45	2.10	2.08	3.06

Exhibit 21.01

OGE Energy Corp.
Subsidiaries of the Registrant

Name of Subsidiary	Jurisdiction of Incorporation	Percentage of Ownership
Oklahoma Gas and Electric Company	Oklahoma	100.0
Enogex Inc.	Oklahoma	100.0
Enogex Products Corporation	Oklahoma	100.0
OGE Energy Resources, Inc.	Oklahoma	100.0

The above listed subsidiaries have been consolidated in the Registrant’s financial statements.

Exhibit 23.01

CONSENT OF INDEPENDENT AUDITORS

We consent to the incorporation by reference in the Registration Statement (Form S-8 No. 333-71327) pertaining to the stock incentive plan, the Registration Statement (Form S-8 No. 333-92423) pertaining to the deferred compensation plan, the Registration Statement (Form S-8 No. 333-104497) pertaining to the retirement savings plan, the Registration Statement (Form S-3 No. 333-104552) pertaining to debt securities, common stock and preferred share purchase rights and the Registration Statement (Form S-3 No. 333-104263) pertaining to the dividend reinvestment plan, of our report dated January 30, 2004, with respect to the consolidated financial statements and schedule of OGE Energy Corp. included in the Annual Report (Form 10-K) for the year ended December 31, 2003.

/s/ Ernst & Young LLP
Ernst & Young LLP

Oklahoma City, Oklahoma
March 3, 2004

Exhibit 24.01

POWER OF ATTORNEY

WHEREAS, OGE ENERGY CORP., an Oklahoma corporation (herein referred to as the “Company”), is about to file with the Securities and Exchange Commission, under the provisions of the Securities Exchange Act of 1934, as amended, its annual report on Form 10-K for the year ended December 31, 2003; and

WHEREAS, each of the undersigned holds the office or offices in the Company herein-below set opposite his or her name, respectively;

NOW, THEREFORE, each of the undersigned hereby constitutes and appoints STEVEN E. MOORE, JAMES R. HATFIELD and DONALD R. ROWLETT and each of them individually, his or her attorney with full power to act for him or her and in his or her name, place and stead, to sign his name in the capacity or capacities set forth below to said Form 10-K and to any and all amendments thereto, and hereby ratifies and confirms all that said attorney may or shall lawfully do or cause to be done by virtue hereof.

IN WITNESS WHEREOF, the undersigned have hereunto set their hands this 21st day of January, 2004.

Steven E. Moore, Chairman, Principal Executive Officer and Director	/ s / Steven E. Moore
Herbert H. Champlin, Director	/ s / Herbert H. Champlin
Luke R. Corbett, Director	/ s / Luke R. Corbett
William E. Durrett, Director	/ s / William E. Durrett
Martha W. Griffin, Director	/ s / Martha W. Griffin
John D. Groendyke, Director	/ s / John D. Groendyke
Robert Kelley, Director	/ s / Robert Kelley
Ronald H. White, M.D., Director	/ s / Ronald H. White, M.D
J. D. Williams, Director	/ s / J. D. Williams
James R. Hatfield, Principal Financial Officer	/ s / James R. Hatfield
Donald R. Rowlett, Principal Accounting Officer	/ s / Donald R. Rowlett

STATE OF OKLAHOMA)
) SS
COUNTY OF CANADIAN)

On the date indicated above, before me, Debra Peters, Notary Public in and for said County and State, personally appeared the above named directors and officers of OGE ENERGY CORP., an Oklahoma corporation, and known to me to be the persons whose names are subscribed to the foregoing instrument, and they severally acknowledged to me that they executed the same as their own free act and deed.

IN WITNESS WHEREOF, I have hereunto set my hand and affixed my official seal on the 21st day of January, 2004.

/s/ Debra Peters
Debra Peters
Notary Public in and for the County
of Canadian, State of Oklahoma

My Commission Expires:
May 3, 2007

Exhibit 31.01

CERTIFICATIONS

I, Steven E. Moore, certify that:

1. I have reviewed this annual report on Form 10-K of OGE Energy Corp.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) for the registrant and we have:

a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

b) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

c) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting.

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 8, 2004
/s/ Steven E. Moore

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

Exhibit 31.01

CERTIFICATIONS

I, James R. Hatfield, certify that:

1. I have reviewed this annual report on Form 10-K of OGE Energy Corp.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) for the registrant and we have:

a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

b) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

c) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting.

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 8, 2004
/s/ James R. Hatfield

James R. Hatfield
Senior Vice President and
Chief Financial Officer

Exhibit 32.01

Certification Pursuant to 18 U.S.C. Section 1350
As Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

In connection with the Annual Report of OGE Energy Corp. (the "Company") on Form 10-K for the period ended December 31, 2003, as filed with the Securities and Exchange Commission (the "Report"), each of the undersigned does hereby certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

March 8, 2004

/s/ Steven E. Moore

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

/s/ James R. Hatfield

James R. Hatfield
Senior Vice President and
Chief Financial Officer

Exhibit 99.01

OGE Energy Corp. Cautionary Factors

The Private Securities Litigation Reform Act of 1995 provides a “safe harbor” for forward-looking statements to encourage such disclosures without the threat of litigation providing those statements are identified as forward-looking and are accompanied by meaningful, cautionary statements identifying important factors that could cause the actual results to differ materially from those projected in the statement. Forward-looking statements have been and will be made in written documents and oral presentations of OGE Energy Corp. (the “Company”). Such statements are based on management’s beliefs as well as assumptions made by and information currently available to management. When used in the Company’s documents or oral presentations, the words “anticipate”, “estimate”, “expect”, “objective” and similar expressions are intended to identify forward-looking statements. In addition to any assumptions and other factors referred to specifically in connection with such forward-looking statements, factors that could cause the Company’s actual results to differ materially from those contemplated in any forward-looking statements include, among others, the following:

- Increased competition in the utility industry, including effects of decreasing margins as a result of competitive pressures; industry restructuring initiatives; transmission system operation and/or administration initiatives; recovery of investments made under traditional regulation; nature of competitors entering the industry; retail wheeling; a new pricing structure; and former customers entering the generation market;

- Changing market conditions and a variety of other factors associated with physical energy and financial trading activities including, but not limited to, price, basis, credit, liquidity, volatility, capacity, transmission, currency, interest rate and warranty risks;

- Risks associated with price risk management strategies intended to mitigate exposure to adverse movement in the prices of natural gas on both a global and regional basis, including commodity price changes, market supply shortages, interest rate changes and counter party default;

- Economic conditions including availability of credit, actions of rating agencies and their impact on our ability to access the capital markets, inflation rates and monetary fluctuations;

- Customer business conditions including demand for their products or services and supply of labor and materials used in creating their products and services;

- Financial or regulatory accounting principles or policies imposed by the Financial Accounting Standards Board, the Securities and Exchange Commission, the Federal Energy Regulatory Commission, state public utility commissions, state entities which regulate natural gas transmission, gathering and processing and similar entities with regulatory oversight;

- Availability or cost of capital such as changes in: interest rates, market perceptions of the utility and energy-related industries, the Company or any of its subsidiaries or security ratings;

- Factors affecting utility operations such as unusual weather conditions; catastrophic weather-related damage; unscheduled generation outages, unusual maintenance or repairs; unanticipated changes to fossil fuel or gas supply costs or availability due to higher demand, shortages, transportation problems or other developments; environmental incidents; or electric transmission or gas pipeline system constraints;

- Employee workforce factors including changes in key executives;

- Rate-setting policies or procedures of regulatory entities, including environmental externalities;

- Social attitudes regarding the utility, natural gas and power industries;

- Identification of suitable investment opportunities to enhance shareowner returns and achieve long-term financial objectives through business acquisitions and divestitures;

- Some future investments made by the Company could take the form of minority interests which would limit the Company's ability to control the development or operation of an investment;

- Costs and other effects of legal and administrative proceedings, settlements, investigations, claims and matters, including but not limited to those described in Note 17 of Notes to Consolidated Financial Statements of the Company's Annual Report on Form 10-K for the year ended December 31, 2003, under the caption Commitments and Contingencies;

- Technological developments, changing markets and other factors that result in competitive disadvantages and create the potential for impairment of existing assets;

- Other business or investment considerations that may be disclosed from time to time in the Company's Securities and Exchange Commission filings or in other publicly disseminated written documents.

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