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SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

[X] ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934 (FEE REQUIRED)

OR

[ ] TRANSITION REPORT PURSUANT TO SECTION 13 or 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934 (NO FEE REQUIRED)

For the fiscal year ended December 31, 1999 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 so registered	Name of each exchange on which each class is 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. [X]

As of February 29, 2000, Common Shares outstanding were 77,863,370. Based upon the closing price on the New York Stock Exchange on February 29, 2000, the aggregate market value of the voting stock held by nonaffiliates of the Company was: Common Stock $1,326,618,666.

The proxy statement for the 2000 annual meeting of shareowners is incorporated by reference into Part III of this Report.

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TABLE OF CONTENTS

PART I

ITEM 1. BUSINESS.

THE COMPANY

OGE Energy Corp. (the "Company") is a public utility holding company, which was incorporated in August 1995 in the State of Oklahoma.

The Company is not engaged in any business independent of that conducted through its subsidiaries, Oklahoma Gas and Electric Company ("OG&E"), Enogex Inc. and Enogex Inc.'s subsidiaries ("Enogex"), and OGE Energy Capital Trust I, a financing trust established in 1999.

The Company's principal subsidiary is OG&E and, accordingly, the Company's financial results and condition are substantially dependent at this time on the financial results and conditions of OG&E. OG&E is a regulated public utility engaged in the generation, transmission and distribution of electricity to retail and wholesale customers. OG&E was incorporated in 1902 under the laws of the Oklahoma Territory and is the largest electric utility in the State of Oklahoma. OG&E sold its retail gas business in 1928 and now owns and operates an interconnected electric production, transmission and distribution system which includes eight active generating stations with a total capability of 5,512,599 kilowatts.

Enogex owns and operates approximately 9,700 miles of natural gas transmission and gathering pipelines, has interests in 15 gas processing plants, markets electricity, natural gas and natural gas liquids and invests in the drilling for and production of crude oil and natural gas.

OG&E's regulated utility business has been and will continue to be affected by competitive changes to the utility industry. Significant changes already have occurred in the wholesale electric markets at the Federal level. In both Oklahoma and Arkansas, legislation has been passed to provide for the restructuring of the electric industry with the goal to provide retail customers with the ability to choose their generation suppliers by July 1, 2002 and January 1, 2002, respectively. The Oklahoma Legislature is considering implementation legislation which is expected to be enacted in May, 2000. This legislation, if implemented as proposed, would significantly impact OG&E. See "Electric Operations - Regulation and Rates - Recent Regulatory Matters" for further discussion of these developments.

The Company's executive offices are located at 321 North Harvey, P. O. Box 321, Oklahoma City, Oklahoma 73101-0321; telephone (405) 553-3000.

ELECTRIC OPERATIONS

GENERAL

OG&E furnishes retail electric service in 280 communities and their contiguous rural and suburban areas. During 1999, six other communities and two rural electric cooperatives in Oklahoma and western Arkansas purchased electricity from OG&E for resale. The service area, with an estimated population of 1.8 million, covers approximately 30,000 square miles in Oklahoma and western Arkansas; including Oklahoma City, the largest city in Oklahoma, and Ft. Smith, Arkansas, the second largest city in that state. Of the 286 communities served, 257 are located in Oklahoma and 29 in Arkansas. Approximately 90 percent of total electric operating revenues for the year ended December 31, 1999, 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 for the year was approximately 5,748 megawatts, and occurred on August 11, 1999. OG&E's load responsibility peak demand was approximately 5,569 megawatts on August 11, 1999, resulting in a capacity margin of approximately 10.0 percent. As reflected in the table below and in the operating statistics on page 3, total kilowatt-hour sales decreased 2.2 percent in 1999 as compared to an increase of 4.2 percent in 1998 and a 1.6 percent increase in 1997. In 1999, kilowatt-hour sales to OG&E customers ("system sales") and sales to other utilities and power marketers ("off-system sales") decreased 0.7 percent and 48.6 percent, because of the record heat of 1998. In 1997, total kilowatt-hour sales increased due to continued customer growth.

Variations in kilowatt-hour sales for the three years are reflected in the following table:

SALES (Millions of Kwh)

	1999	Inc/ (Dec)	1998	Inc/ (Dec)	1997	Inc/ (Dec)
System Sales	23,468	(0.7%)	23,642	6.6%	22,183	3.0%
Off-System Sales	374	(48.6%)	728	(39.5%)	1,202	(18.5%)
Total Sales	23,842	(2.2%)	24,370	4.2%	23,385	1.6%

In 1999, OG&E's Sooner Generating Station (consisting of two coal-fired units with an aggregate capability of 1,012 Mw) and OG&E's three coal-fired units at its Muskogee Generating Station (with an aggregate capability of 1,481 Mw) were recognized by an industry survey as being among the top seven percent of more than 400 major coal-fired plants across the United States.

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. See Item 3 "Legal Proceedings" for a further discussion of this matter. 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 "Electric Operations - Regulation and Rates - Recent Regulatory Matters" 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		
	1999	1998	1997
ELECTRIC ENERGY:			
(Millions of Kwh)			
Generation (exclusive of station use)	21,788	22,565	21,620
Purchased	3,795	3,984	3,528
Total generated and purchased	25,583	26,549	25,148
Company use, free service and losses	(1,741)	(2,179)	(1,763)
Electric energy sold	23,842	24,370	23,385
ELECTRIC ENERGY SOLD:			
(Millions of Kwh)			
Residential	7,509	7,959	7,179
Commercial and industrial	11,985	11,912	11,586
Public street and highway lighting	69	68	68
Other sales to public authorities	2,354	2,352	2,202
System sales for resale	1,551	1,351	1,148
Total system sales	23,468	23,642	22,183
Off-system sales	374	728	1,202
Total sales	23,842	24,370	23,385
ELECTRIC OPERATING REVENUES:			
(Thousands)			
Electric Revenues:			
Residential	$ 515,299	$ 537,486	$ 474,419
Commercial and industrial	557,884	554,589	526,673
Public street and highway lighting	9,736	9,618	9,456
Other sales to public authorities	108,159	110,522	98,818
System sales for resale	42,918	38,763	34,667
Total system sales	1,233,996	1,250,978	1,144,033
Off-system sales	27,894	37,435	23,028
Total Electric Revenues	1,261,890	1,288,413	1,167,061
Miscellaneous	24,954	23,665	24,629
Total Operating Revenues	$ 1,286,844	$ 1,312,078	$ 1,191,690
NUMBER OF ELECTRIC CUSTOMERS:			
(At end of period)			
Residential	599,702	598,378	593,699
Commercial and industrial	86,837	86,251	85,315
Public street and highway lighting	249	249	249
Other sales to public authorities	11,151	11,183	10,897
Sales for resale	56	39	40
Total	697,995	696,100	690,200
RESIDENTIAL ELECTRIC SERVICE:			
Average annual use (Kwh)	12,546	13,342	12,133
Average annual revenue	$ 860.98	$ 900.94	$ 801.74
Average price per Kwh (cents)	6.86	6.75	6.61

REGULATION AND RATES

OG&E's retail electric tariffs in Oklahoma are regulated by the Oklahoma Corporation Commission ("OCC"), and in Arkansas by the Arkansas Public Service Commission ("APSC"). 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 Federal Energy Regulatory Commission ("FERC"). The Secretary of the Department of Energy has jurisdiction over some of OG&E's facilities and operations.

As part of the corporate reorganization whereby the Company became the holding company parent of OG&E, OG&E obtained the approval of the OCC. The order of the OCC authorizing OG&E to reorganize into a holding company structure 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 and its subsidiaries 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.

For the year ended December 31, 1999, approximately 87 percent of OG&E's electric revenue was subject to the jurisdiction of the OCC, eight percent to the APSC, and five percent to the FERC.

RECENT REGULATORY MATTERS

In February 1997, the OCC issued an order (the "1997 Order") that, among other things, effectively lowered OG&E's rates to its Oklahoma retail customers by $50 million annually (based on a test year ended December 31, 1995). Of the $50 million rate reduction, approximately $45 million became effective on March 5, 1997, and the remaining $5 million became effective March 1, 1998. The 1997 Order also directed OG&E to commence competitively bid gas transportation service to its gas-fired plants no later than April 30, 2000. The order also set annual compensation for the transportation services provided by Enogex to OG&E at $41.3 million annually until March 1, 2000, at which time the rate would drop to $28.5 million (reflecting the completion of the recovery from ratepayers of the amortization premium paid by OG&E when it acquired Enogex in 1986) and remain at that level until competitively-bid gas transportation begins. Final firm bids were submitted by Enogex and other pipelines on April 15, 1999. In July 1999, OG&E filed an application with the OCC requesting approval of a performance-based rate plan for its Oklahoma retail customers from April 2000 until the introduction of customer choice for electric power in July 2002. As part of this application, OG&E stated that Enogex had submitted the only viable bid ($33.4 million per year) for gas transportation to its six gas-fired power plants that were the subject of the competitive bid. As part of its application to the OCC, OG&E offered to discount Enogex's bid from $33.4 million annually to $25.2 million annually. OG&E has executed a new gas transportation contract with Enogex under which Enogex would continue serving the needs of OG&E's power plants at a price to be paid by OG&E of $33.4 million annually and, if OG&E's proposal had been approved by the OCC, OG&E would have recovered a portion of such amount ($25.2 million) from its ratepayers. The OCC Staff (the "Staff"), the Office of the Oklahoma Attorney General and a coalition of industrial customers filed testimony questioning various parts of OG&E's performance-based rate plan, including the result of the competitive bid process, and suggested, among other things, that the bidding process be repeated or that gas transportation service to five of OG&E's gas-fired plants be awarded to parties other than Enogex. The Staff also filed testimony stating in substance that OG&E's electric rates as a whole were appropriate and did not warrant a rate review. OG&E negotiated with these parties in an effort to settle all issues (including the competitive bid process) associated with its application for a performance-based rate plan. When these negotiations failed, OG&E withdrew its application, which withdrawal was approved by the OCC in December 1999. Based on filed testimony, OG&E believes that Enogex properly won the competitive bid and, unless OG&E's decision to award its gas transportation service to Enogex is abrogated by order of the OCC (which order is upheld on appeal), that it intends to fulfill its obligations under its new gas transportation contract with Enogex at a price of $33.4 million annually. Whether OG&E will be able to recover the entire amount from its ratepayers has not been determined as explained below.

The 1997 Order also contained the Generation Efficiency Performance Rider ("GEP Rider"), which is designed so that when OG&E's average annual cost of fuel per kwh is less than 96.261 percent of the average non-nuclear fuel cost per kwh of certain other investor-owned utilities in the region, OG&E is allowed to collect, through the GEP Rider, one-third of the amount by which OG&E's average annual cost of fuel comes in below 96.261 percent of the average of the other specified utilities. If OG&E's fuel cost exceeds 103.739 percent of the stated average, the Company will not be allowed to recover one-third of the fuel costs above that average from Oklahoma customers. As explained below, the GEP Rider is currently under review by the OCC.

The fuel cost information used to calculate the GEP Rider is based on fuel cost data submitted by each of the utilities in their Form No. 1 Annual Report filed with the FERC. The GEP Rider is revised effective July 1 of each year to reflect any changes in the relative annual cost of fuel reported for the preceding calendar year. For 1999, the GEP Rider contributed approximately $20.8 million to revenues, which was approximately $9.5 million, or approximately $0.07 per share lower than 1998. The current GEP Rider is estimated to positively impact revenue by $13.1 million or approximately $0.10 per share during the 12 months ending June 2000.

On January 12, 2000, the Staff filed three applications to address various aspects of OG&E's electric rates. Two of the applications were expected, while the third pertains to recoveries under OG&E's fuel adjustment clause. The first application relates to the completion of the recovery of the amortization premium paid by OG&E when it acquired Enogex in 1986 and the resulting removal of this $12.8 million from the amounts currently being paid annually by OG&E to Enogex and being recovered by OG&E from its ratepayers. OG&E has consented to this action. The second application relates to a review of the GEP Rider, which, as part of the OCC's 1997 Order, was scheduled for review in March 2000. OG&E collected approximately $20.8 million pursuant to the GEP Rider during 1999. A hearing on the GEP Rider is scheduled in May 2000 and OG&E intends to support the retention of the GEP Rider with only minor modifications. The final application relates to a review of 1999 fuel cost recoveries. OG&E assumes that this application also will be used to address the competitive bid process of its gas transportation service. The Company cannot predict the precise outcome of these proceedings at this time, but does not expect that they will have a material effect on its operations.

On February 13, 1998, the APSC Staff filed a motion for a show cause order to review OG&E's electric rates in the State of Arkansas. The Staff recommended a $3.1 million annual rate reduction (based on a test year ended December 31, 1996). The Staff and OG&E reached a settlement for a $2.3 million annual rate reduction, which was approved by the APSC in August 1999.

STATE RESTRUCTURING INITIATIVES

OKLAHOMA: As previously reported, Oklahoma enacted in April 1997 the Electric Restructuring Act of 1997 (the "Act"). In June 1998, various amendments to the Act were enacted. If implemented as proposed, the Act will significantly affect OG&E's future operations. The following summary of the Act does not purport to be complete and is subject to the specific provisions of the Act, which is codified at Sections 190.2 et. seq. of Title 17 of the Oklahoma Statutes.

The Act consists of eight sections, with Section 1 designating the name of the Act. Section 2 describes the purposes of the Act, which is generally to restructure the electric industry to provide for more competition and, in particular, to provide for the orderly restructuring of the electric utility industry in the State of Oklahoma in order to allow direct access by retail consumers to the competitive market for the generation of electricity while maintaining the safety and reliability of the electric system in the state.

The primary goals of a restructured electric utility industry, as set forth in Section 2 of the Act, are as follows:

l. To reduce the cost of electricity for as many consumers as possible, helping industry to be more competitive, to create more jobs in Oklahoma and help lower the cost of government by reducing the amount and type of regulation now paid for by taxpayers;

2. To encourage the development of a competitive electricity industry through the unbundling of prices and services and separation of generation services from transmission and distribution services;

3. To enable retail electric energy suppliers to engage in fair and equitable competition through open, equal and comparable access to transmission and distribution systems and to avoid wasteful duplication of facilities;

4. To ensure that direct access by retail consumers to the competitive market for generation be implemented in Oklahoma by July 1, 2002; and

5. To ensure that proper standards of safety, reliability and service are maintained in a restructured electric service industry.

Section 3 of the Act sets forth various definitions and exempts in large part several electric cooperatives and municipalities from the Act unless they choose to be governed by it.

Sections 4, 5 and 6 of the Act are designed to implement the goals of the Act and provide for various studies and task forces to assess the issues and consequences associated with the proposed restructuring of the electric utility industry. In Section 4, the Joint Electric Utility Task Force (the "Joint Task Force"), which is described below, is directed to undertake a study of all relevant issues relating to restructuring the electric utility industry in Oklahoma including, but not limited to, the issues set forth in Section 4, and to develop a proposed electric utility framework for Oklahoma. The OCC is prohibited from promulgating orders relating to the restructuring without prior authorization of the Oklahoma Legislature. Also, in developing a framework for a restructured electric utility industry, the OCC is to adhere to fourteen principles set forth in Section 4, including the following:

1. Appropriate rules shall be promulgated, ensuring that reliable and safe electric service is maintained.

2. Consumers shall be allowed to choose among retail electric energy suppliers to help ensure competitive and innovative markets. A process should be

established whereby all retail consumers are permitted to choose their retail electric energy suppliers by July 1, 2002.

3. When consumer choice is introduced, rates shall be unbundled to provide clear price information on the components of generation, transmission and distribution and any other ancillary charges. Charges for public benefit programs currently authorized by statute or the OCC, or both, shall be unbundled and appear in line item format on electric bills for all classes of consumers.

4. An entity providing distribution services shall be relieved of its traditional obligation to provide electric supply but shall have a continuing obligation to provide distribution service for all consumers in its service territory.

5. The benefits associated with implementing an independent system planning committee composed of owners of electric distribution systems to develop and maintain planning and reliability criteria for distribution facilities shall be evaluated.

6. A defined period for the transition to a restructured electric utility industry shall be established. The transition period shall reflect a suitable time frame for full compliance with the requirements of a restructured utility industry.

7. Electric rates for all consumer classes shall not rise above current levels throughout the transition period. If possible, electric rates for all consumers shall be lowered when feasible as markets become more efficient in a restructured industry.

8. The OCC shall consider the establishment of a distribution access fee to be assessed to all consumers in Oklahoma connected to electric distribution systems regulated by the OCC. This fee shall be charged to cover social costs, capital costs, operating costs, and other appropriate costs associated with the operation of electric distribution systems and the provision of electric services to the retail consumer.

9. Electric utilities have traditionally had an obligation to provide service to consumers within their established service territories and have entered into contracts, long-term investments and federally mandated cogeneration contracts to meet the needs of consumers. These investments and contracts have resulted in costs, which may not be recoverable in a competitive restructured market and thus may be "stranded." Procedures shall be established for identifying and quantifying stranded investments and for allocating costs; and mechanisms shall be proposed for for recovery of an appropriate amount of prudently incurred, unmitigable and verifiable stranded costs and investments. As As part of this process, each entity shall be required to propose propose a recovery plan which establishes its unmitigable and verifiable stranded costs and investments and a limited recovery period designed to recover such costs expeditiously, provided that the recovery period and the amount of qualified transition costs shall yield a transition charge which shall not cause the total price for electric power, including transmission and distribution services, for any consumer to exceed the cost per kilowatt-hour paid on the effective date of this Act during the transition

period. The transition charge shall be applied to all consumers including direct access consumers, and shall not disadvantage one class of consumer or supplier over another, not impede competition and shall be allocated over a period of not less than three (3) years nor more than seven (7) years.

10. It is the intent that all transition costs shall be recovered by virtue of the savings generated by the increased efficiency in markets brought about by restructuring of the electric utility industry. All classes of consumers shall share in the transition costs.

Subject to the principles set forth in Section 4, the Joint Task Force is directed to prepare a four-part study. As a result of the 1998 amendments, the time frame for the delivery of the remaining parts of the Study was accelerated to October 1, 1999. This study addressed: (i) technical issues (including reliability, safety, unbundling of generation, transmission and distribution services, transition issues and market power); (ii) financial issues (including rates, charges, access fees, transition costs and stranded costs); (iii) consumer issues (such as the obligation to serve, service territories, consumer choices, competition and consumer safeguards); and (iv) tax issues (including sales and use taxes, ad valorem taxes and franchise fees).

Section 5 of the Act directs the Joint Task Force to study and submit a report on the impact of the restructuring of the electric utility industry on state tax revenues and all other facets of the current utility tax structure on the state and all political subdivisions of the state. The Oklahoma Tax Commission and the OCC are precluded from issuing any rules on such matters without the approval of the Oklahoma Legislature. Also, the Act requires the establishment, on or before July 1, 2002, of a uniform tax policy that allows all competitors to be taxed on a fair and equitable basis.

Section 6 creates the Joint Task Force, which shall consist of seven members from the Oklahoma Senate and seven members from the Oklahoma House of Representatives. The Joint Task Force is directed to undertake the studies set forth in Sections 4 and 5 of the Act. The Joint Task Force is permitted to make final recommendations to the Governor and Oklahoma Legislature. The Joint Task Force is also empowered to retain consultants to study the creation of an Independent System Operator, which would coordinate the physical supply of electricity throughout Oklahoma and maintain reliability, security and stability of the bulk power system. In addition, such study shall assess the benefits of establishing a power exchange that would operate as a power pool allowing power producers to compete on common ground in Oklahoma. In fulfilling its tasks, the Joint Task Force can appoint advisory councils made up of electric utilities, regulators, residential customers and other constituencies.

Section 7 provides generally that, with respect to electric distribution providers, no customer switching will be allowed from the effective date of the Act until July 1, 2002, except by mutual consent. It also provides that any municipality that fails to become subject to the Act will be prohibited from selling power outside its municipal limits except from lines owned on the effective date of the Act. Furthermore, this section provides generally that out-of-state suppliers of electricity and their affiliates who make retail sales of electricity in Oklahoma through the use of transmission and distribution facilities of in-state suppliers must provide equal access to their transmission and distribution facilities outside of Oklahoma. Section 8 sets forth the effective date of the Act as April 25, 1997.

Another provision of the Act enacted in 1998 requires a uniform tax policy be established by July 1, 2002. The Act was modified during the 1999 session of the Oklahoma Legislature to clarify certain ambiguities by defining key terms in the Act.

With the completion of the studies described above in October 1999, the Oklahoma legislature is expected to implement additional legislation, which will address many specific issues associated with deregulation. Several bills have already been introduced. While the Company cannot predict the terms of the new legislation, the Company intends to participate actively in the legislative process.

The OCC has adopted rules that are designed to make the gas utility business in Oklahoma more competitive. These rules do not impact the electric industry. Yet, if implemented, the rules are expected to offer increased opportunities to Enogex's pipeline and related businesses.

ARKANSAS: In December 1997, the APSC established four generic proceedings to consider the implementation of a competitive retail electric market in the State of Arkansas. During 1998, the APSC held hearings to consider competitive retail generation, market structure, market power, taxation, recovery and mitigation of stranded costs, service and reliability, low income assistance, independent system operators and transition issues. The Company participated actively in those proceedings, and in October 1998 the APSC issued its report to the Arkansas Legislature recommending competitive retail electric generation to begin no later than January 1, 2002. Several bills calling for electric industry restructuring were introduced after the Arkansas General Assembly began its 1999 session.

In April 1999, Arkansas became the 18th state to pass a law calling for restructuring of the electric utility industry at the retail level. The new law targets customer choice of electricity providers by January 1, 2002. The new law also provides that utilities owning or controlling transmission assets must transfer control of such transmission assets to an independent system operator, independent transmission company or regional transmission group, if any such organization has been approved by the FERC. Other provisions of the new law permit municipal electric systems to opt in or out, permit recovery of stranded costs and transition costs and require unbundled rates by July 1, 2000 for generation, transmission, distribution and customer service. The APSC has established a timetable to establish rules implementing the Arkansas restructuring statutes. The new law will significantly affect OG&E's future Arkansas operations. OG&E's electric service area includes parts of western Arkansas, including Ft. Smith, the second-largest metropolitan market in the state.

AUTOMATIC FUEL ADJUSTMENT CLAUSES

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

NATIONAL ENERGY LEGISLATION

Federal law imposes numerous responsibilities and requirements on OG&E. The Public Utility Regulatory Policies Act of 1978 requires electric utilities, such as OG&E, to purchase electric power from, and sell electric power to, qualified cogeneration facilities and small power production facilities ("QFs"). Generally stated, electric utilities must purchase electric energy and production capacity made available by QFs 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. See "Finance and Construction." Electric utilities also must furnish electric energy to QFs on a non-discriminatory basis at a rate that is just and reasonable and in the public interest and must provide certain types of service which may be requested by QFs to supplement or back up those facilities' own generation.

The Energy Policy Act of 1992 ("Energy Act") has resulted in some significant changes in the operations of the electric utility industry and the federal policies governing the generation, transmission and sale of electric power. The Energy Act, among other things, authorized the FERC to order transmitting utilities to provide transmission services to any electric utility, Federal power marketing agency, or any other person generating electric energy for sale or resale, at transmission rates set by the FERC. The Energy Act also is designed to promote competition in the development of wholesale power generation in the electric industry. It exempts a new class of independent power producers from regulation under the Public Utility Holding Company Act of 1935.

Within four years of the enactment of the Energy Act, FERC issued Order 888 and Order 889 to facilitate third-party utilization of the transmission grid as the vehicle for developing a more competitive wholesale bulk power market. Order 888 requires all transmission owners to (i) offer comparable open-access transmission service for wholesale transactions under a tariff of general applicability on file at FERC and (ii) take transmission service for their own wholesale sales under their open-access tariff. Order 889 requires electric utilities to functionally separate their transmission and reliability functions from their wholesale power marketing functions. In this connection, Order 889 required electric utilities to develop and maintain an Open Access Same-Time Information System ("OASIS") to ensure that transmission customers have access to transmission information, through electronic means, that will enable them to obtain open-access transmission service on a basis comparable to a transmitting utility's own use of its system.

OG&E is a member of the Southwest Power Pool ("SPP"), the regional reliability organization for Oklahoma, Arkansas, Kansas, Louisiana, Missouri and part of 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. The SPP has asked for FERC recognition as an Independent System Operator ("ISO") consistent with FERC's guidelines in its Order 888.

Another impact of complying with FERC's Order 888 is a requirement for utilities to offer a transmission tariff that includes network transmission service ("NTS") to transmission customers. NTS allows transmission service customers to fully integrate load and resources on an instantaneous basis, in a manner similar to how OG&E has historically integrated its load and resources. Under NTS, OG&E and participating customers share the total annual transmission cost for their combined joint-use systems, net of related transmission revenues, based upon each company's share of the total system load. Management expects minimal annual expenses as a result of Orders 888 and 889.

In December 1999, the FERC issued Order 2000 to advance the formation of Regional Transmission Organizations ("RTOs"). The rule requires that each public utility that owns, operates or controls facilities for the transmission of electric energy in interstate commerce file by October 15, 2000, a proposal with respect to forming and participating in an RTO. The FERC also codified minimum characteristics and functions that a transmission entity must satisfy in order to be considered an RTO. The FERC's goal is to promote efficiency in wholesale electricity markets and to ensure that electricity consumers pay the lowest price possible for reliable service. The FERC expects that the RTOs will be operational by December 15, 2001.

REGULATORY ASSETS AND LIABILITIES

As discussed previously, Oklahoma and Arkansas enacted legislation that will restructure the electric utility industry in those states, assuming that all the conditions in the legislation are met. This legislation would deregulate OG&E's electric generation assets and the continued use of Statement of Financial Accounting Standards ("SFAS") No. 71, "Accounting for the Effects of Certain Types of Regulation", with respect to the related regulatory assets may no longer be appropriate. 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 of up to $30 million, depending on the transition mechanisms developed by the legislature for the recovery of all or a portion of these net regulatory assets.

The enacted Oklahoma and Arkansas legislation does 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 assets is appropriate. However, if utility regulators in Oklahoma and Arkansas were to adopt regulatory methodologies in the future that are not based on cost-of-service, the continued use of SFAS No. 71 with respect to the regulatory assets 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 proposal in Oklahoma, the Arkansas legislation and other factors are expected to significantly increase competition in the electric industry. The Company has taken steps in the past and intends to take appropriate steps in the future to remain a competitive supplier of electricity. Past actions include a redesign and restructuring effort in 1994, continuing actions to reduce fuel costs, improvements in customer service, installation of the SAP Enterprise Software and efforts to improve OG&E's electric transmission and distribution network to reduce outages, all of which enhance OG&E's ability to deliver electricity competitively. While the Company is supportive of competition, it believes that all electric suppliers must be required to compete on a fair and equitable basis and the Company is advocating this position vigorously.

RATE STRUCTURE, LOAD GROWTH AND RELATED MATTERS

Two of OG&E's primary goals are: (i) to increase electric revenues by attracting and expanding job-producing businesses and industries; and (ii) to encourage the efficient electrical energy use by all of OG&E's customers. In order to meet these goals, OG&E has reduced and restructured its rates to its customers. At the same time, OG&E had implemented numerous energy efficiency programs and tariff schedules. In 1999, these programs and schedules included: (i) the "Surprise Free Guarantee" program, which guarantees residential customers comfort and annual energy consumption for heating, cooling and water heating for new homes built to energy efficient standards; (ii) a load curtailment rate for industrial and commercial customers who can demonstrate a load curtailment of at least 500 kilowatts; and (iii) the time-of-use rate schedules for various commercial, industrial and residential customers designed to shift energy usage from peak demand periods during the hot summer afternoon to non-peak hours.

OG&E made it's pilot Real Time Pricing ("RTP") program permanent in 1999. The program was first implemented in 1996 for qualifying industrial and commercial customers. This tariff gives customers additional options on total kilowatt-hour growth and the control of growth of peak demand. RTP is a tariff option, which prices electricity so that the current price varies hourly with short notice to reflect current expected costs. The RTP technique will allow a measure of competitive pricing, a broadening of customer choice, the balancing of electricity usage and capacity in the short-and long-term, and provide customers assistance in controlling their costs.

OG&E's 1999 marketing efforts included geothermal heat pumps, electrotechnologies, electric food service promotion and a heat pump promotion in the residential, commercial and industrial markets. OG&E works closely with individual customers to provide the best information on how current technologies can be combined with OG&E's marketing programs to maximize the customer's benefit.

Electric and magnetic fields ("EMFs") surround all electric tools and appliances, internal home wiring and external power lines such as those owned by OG&E. During the last several years considerable attention has focused on possible health effects from EMFs. While some studies indicate a possible weak correlation, other similar studies indicate no correlation between EMFs and health effects. As part of the Energy Act Congress established the National EMF Research and Public Information Dissemination ("RAPID") Program to address the question of whether EMF posed a risk to human health. In the National Institute of Environmental Health Sciences ("NIEHS") report of June 1999 with regard to the findings of RAPID, it is concluded that it is their belief that the probability of EMF exposure truly being a health hazard is currently small. The nation's electric utilities, including OG&E, have participated with the Electric Power Research Institute ("EPRI") in the sponsorship of more than $75 million in research to determine the possible health effects of EMFs. In addition, during the past decade OG&E has cooperatively funded Edison Electric Institute ("EEI") research to study the possible health effects of EMFs. Through its participation with the EPRI and EEI, OG&E will continue its support of the research with regard to the possible health effects of EMFs. OG&E is dedicated to delivering electric service in a safe, reliable, environmentally acceptable and economical manner.

FUEL SUPPLY

During 1999, approximately 71 percent of the OG&E-generated energy was produced by coal-fired units and 29 percent by natural gas-fired units. A slight decline in the percentage of coal generation in future years is expected to result from increases in natural gas-fired generation required to meet growing energy needs while coal generation will remain fairly constant. Over the last 5 years, the average cost of fuel used, by type, per million Btu was as follows:

	1999	1998	1997	1996	1995
Coal..................	$0.85	$0.85	$0.84	$0.83	$0.83
Natural Gas...........	$3.14	$2.83	$3.60	$3.61	$3.19
Weighted Avg..........	$1.54	$1.48	$1.39	$1.45	$1.41

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 "Electric Operations - - Regulation and Rates - Automatic Fuel Adjustment Clauses."

COAL-FIRED UNITS: All OG&E coal units, with an aggregate capability of 2,493 megawatts, are designed to burn low sulfur western coal. OG&E purchases coal under a mix of long- and short-term contracts. During 1999, OG&E purchased 11.5 million tons of coal from the following Wyoming suppliers: Caballo Rojo Complex, Kennecott Energy Company, Thunder Basin Coal Company, Powder River Coal Company, and Triton Coal Company. The combination of all coals has a weighted average sulfur content of 0.3 percent and can be burned in these units under existing federal, state and local environmental standards (maximum of 1.2 pounds of sulfur dioxide per million Btu) without the addition of sulfur dioxide removal systems. Based upon the average sulfur content, OG&E units have an approximate emission rate of 0.63 pounds of sulfur dioxide per million Btu. In anticipation of the more strict provisions of Phase II of The Clean Air Act, starting in the year 2000, OG&E has contracts in place that will allow for a supply of very low sulfur coal from suppliers in the Powder River Basin to meet the new sulfur dioxide standards.

OG&E has continued its efforts to maximize the utilization of its coal units by optimizing the boiler operations 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.

GAS-FIRED UNITS: For calendar year 2000, OG&E expects to acquire less than 1 percent of its gas needs from long-term gas purchase contracts. The remainder of OG&E's gas needs during 2000 will be supplied by contracts with at-market pricing. These volumes of gas will be acquired through day-to-day purchases on the spot market, as well as monthly purchase agreements.

In 1993, OG&E began utilizing a natural gas storage facility which helps lower fuel costs by allowing OG&E to optimize economic dispatch between fuel types and take advantage of seasonal variations in natural gas prices. By diverting gas into storage during low demand periods, OG&E is able to use as much coal as possible to generate electricity and utilize the stored gas to meet the additional demand for electricity.

ENOGEX

The Company's wholly-owned non-utility subsidiary, Enogex Inc. is an Oklahoma intrastate natural gas pipeline which also conducts operations in related businesses through subsidiary companies. These businesses include gas processing operations and natural gas liquids marketing ("Gas Processing") conducted by Enogex Products Corporation ("Products") and a subsidiary of Transok Holding LLC ("Transok"); exploration and production of oil and natural gas ("Exploration and Production") conducted through Enogex Exploration Corporation ("Exploration"); marketing of natural gas, natural gas liquids, and electricity ("Marketing") conducted primarily by OGE Energy Resources Inc. ("Resources") and Transok; and the gas gathering and interstate gas transmission operations ("Gas Transportation") conducted by Enogex Arkansas Pipeline Company ("EAPC"), Enogex Gas Gathering LLC ("EGG") and Transok.

For the year ended December 31, 1999, and before elimination of intercompany items between OG&E and Enogex, Enogex's consolidated revenues and net income were approximately $1.0 billion and $21.7 million, respectively.

Recent Actions. Enogex is the exclusive transporter of natural gas to OG&E's electric power generating stations. The OCC, the regulatory body which sets OG&E's electric rates, issued an order on February 11, 1997 directing OG&E to commence competitively bid gas transportation service to its gas-fired plants no later than April 30, 2000. The order also set annual compensation that can be recovered from ratepayers for the transportation services provided by Enogex to OG&E at $41.3 million annually until March 1, 2000, at which time the rate would drop to $28.5 million and remain in effect until competitively-bid gas transportation begins. On November 30, 1998, OG&E issued a detailed Request for Proposal ("RFP") to potential transportation bidders to begin the process of competitive bidding. Final firm bids were submitted by Enogex and others on April 15, 1999. In July 1999, OG&E filed an application with the OCC requesting approval of a performance-based rate plan for its Oklahoma retail customers from April 2000 until the introduction of customer choice for electric power in July 2002. As part of this application, OG&E stated that Enogex had submitted the only viable bid ($33.4 million per year) for gas transportation to its six gas-fired power plants that were the subject of the competitive bid. As part of its application to the OCC, OG&E offered to discount Enogex's bid from $33.4 million annually to $25.2 million annually. Enogex has executed a new gas transportation contract with OG&E under which Enogex will continue serving the needs of OG&E's power plants identified in the RFP at a price to be paid by OG&E of $33.4 million annually. The Company cannot predict what further action the OCC or others may take regarding the competitive bid process. These actions could include hearings by the OCC and attempts to force OG&E to use parties other than Enogex for its gas transportation service. Based on filed testimony and advice from OG&E, Enogex believes that it properly won the competitive bid and, unless OG&E's decision to award its gas transportation service to Enogex is abrogated by order of the OCC (which order is upheld on appeal), OG&E will fulfill its obligations under its new gas transportation contract with Enogex at a price of $33.4 million annually. As a result of the foregoing, Enogex expects that revenues generated from its transportation services for OG&E (which in 1998 and 1999 represented 8.2 percent and 3.8 percent, respectively, of Enogex's consolidated revenues) will remain at a rate of $41.3 million per year until April 30, 2000 and will decline to $33.4 million thereafter. Whether OG&E will be able to recover the full amount from its ratepayers has not been determined.

Enogex plans to diversify its revenue and income sources by increasing revenues and net income from transmission services provided to third parties, by increasing the revenues and net income from

Enogex subsidiaries' natural gas gathering and processing, by continuing development and production operations around our systems, and by actively pursuing potential acquisitions of complementary businesses or assets.

In May 1997, Products acquired an 80 percent interest in the NuStar Joint Venture from Nuevo Liquids Inc. for $26 million. The joint venture assets include a 66.67 percent interest in the Benedum gas processing plant with an inlet capacity of 110 million cubic feet per day; a 100 percent interest in a second processing plant with a capacity of 30 million cubic feet per day; 52 miles of natural gas liquid pipeline and over 200 miles of related gas gathering facilities located in Upton, Crockett, Reagan and neighboring counties in the Permian Basin in West Texas.

In January 1998, Enogex, through its newly formed subsidiary EAPC, acquired a 40 percent interest in NOARK Pipeline Systems, L.P. ("NOARK"), for approximately $30 million and agreed to acquire the assets of Ozark Pipeline ("Ozark"), for approximately $55 million. In July 1998, EAPC completed its acquisition of Ozark and contributed Ozark to NOARK. The two pipelines were integrated into a single, interstate transmission system, Ozark Gas Transmission LLC ("OGT") on November 1, 1998 at an additional cost of approximately $15 million. EAPC, which funded the integration, owns a 75 percent interest in NOARK and Southwestern Energy Pipeline Company owns the remaining 25 percent interest in the partnership. Current capacity of the integrated system is approximately 330 million cubic feet per day.

The fees charged by Ozark and by NOARK's second interstate pipeline, Arkansas Western Pipeline ("AWP") are subject to regulation by the FERC. AWP is an eight-mile pipeline segment crossing the border between eastern Arkansas and Missouri. In November 1998, the FERC approved a maximum lawful rate of $0.2455 per mmbtu for OGT. AWP's current maximum lawful rate is $0.0311 per mmbtu.

In July 1998, Products acquired Belvan Corporation and the Belvan Partners, L.P. and Todd Ranch Partners, L.P. which possess gathering, processing and treating assets in the vicinity of Products' NuStar processing operations in Crockett, Upton and Reagan Counties in West Texas. Acquired assets included 345 miles of gathering system, capable of gathering approximately 15 million cubic feet per day from 250 wells, natural gas liquid recovery facilities and sulfur recovery facilities with an effective current capacity of 15 million cubic feet per day and an eight-mile natural gas liquids pipeline. The acquisition cost was approximately $13.7 million.

In July 1998, Enogex entered into a capital lease of 5 billion cubic feet of firm gas storage capacity plus certain rights to an additional 8 billion cubic feet of capacity in an existing gas storage field located in Hughes County, Oklahoma. The lease was for five years firm with seven five-year renewal terms for a total of 40 years, and provides for annual rental payments of $1.1 million payable quarterly. The first three renewal terms provide for annual payments of $900,000 and the remaining terms provide for annual payments of $100,000. Enogex paid $10.5 million on execution of the agreement. This storage, which can accommodate injections of up to 150 million cubic feet per day and withdrawals of up to 400 million cubic feet per day, has enhanced the operating flexibility of Enogex in serving end-user markets and has permitted Enogex to capture seasonal swings in the value of system supply gas.

In July 1999, Enogex acquired Transok. Transok's principal assets include approximately 4,900 miles of natural gas gathering and transmission pipelines and related compression assets located in Oklahoma and Texas with a current throughput of approximately 1.1 billion cubic feet per day and a 18 billion cubic feet underground gas storage field at Greasy Creek, Oklahoma. Transok also owns nine gas processing plants with inlet capacities totaling 779 million cubic feet per day, which produce approximately 26,500 gross barrels per day of natural gas liquids. Enogex purchased Transok from Tejas Energy LLC, an affiliate of Shell Oil Company, for approximately $710.3 million, which included acquisition costs, reserves and assumption of $173 million of long term debt.

Gas Transportation. One of Enogex's primary lines of business is the transportation of natural gas, which includes both interstate and intrastate transportation along with natural gas gathering. This business is conducted by Enogex and several of its subsidiaries in Oklahoma, Arkansas and Texas. Interruptible transportation service is offered to most interstate and intrastate pipelines and end-users connected to Enogex's systems. Enogex and its subsidiaries operate approximately 9,700 miles of pipeline that gather and transport gas from the Arkoma basin of eastern Oklahoma and Arkansas, the Anadarko basin of western Oklahoma and the Permian basin of West Texas.

As stated above, the Company completed in July 1999 its acquisition of Transok. Transok was established in 1955 to transport boiler fuel to the gas-powered electric generating facilities of Public Service Company of Oklahoma ("PSO"). PSO, a subsidiary of Central and South West Corporation, is the second largest electric utility in Oklahoma, serving the Tulsa market. Transok was acquired by PSO in 1961 and maintained a sole-supplier relationship with PSO until 1998, when ONG 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, PSO remains an important customer of Transok services. Transok continues to provide gas transmission delivery services to all of PSO's gas-fueled electric generation units in Oklahoma under a firm intrastate transportation contract. The current contract, which expires January 1, 2003, provides for a monthly demand charge plus a variable transportation rate depending on the origins of the gas supply being transported. In addition, Transok provides straight fee transportation services to West Texas Utilities ("WTU"), an affiliate of PSO, for gas delivery service to certain WTU generating stations in the Texas Panhandle under a contract that expires on December 31, 2004. In 1999, Transok's revenues from the PSO and WTU contracts were $14.5 million and $2.5 million respectively.

The rates charged by Enogex and Transok 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 FERC under Section 311 of the Natural Gas Policy Act. The statute entitles Enogex and Transok to charge a "fair and equitable" rate that is 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. In addition, Enogex and Transok have agreed to open their systems to all interstate shippers that are interested in transporting natural gas through the systems. Enogex and Transok are required to conduct this transportation on a non-discriminatory basis, although this transportation is subordinate to that performed for OG&E and PSO. This decision does not increase appreciably the federal regulatory burden on Enogex and Transok, but does give Enogex and Transok the opportunity to utilize any unused capacity on an interruptible basis and thus increase its transportation revenues.

Gas Processing. Products has been active since 1968 in the processing of natural gas and marketing of natural gas liquids. With the acquisition of Transok, Enogex is now the largest gas processor in the State of Oklahoma. The NuStar Joint Venture, in which Products owns an 80 percent interest, has been engaged in the processing of natural gas since 1951. Products' and NuStar's natural gas processing plant operations consist of the extraction and sale of natural gas liquids. Transok's gas processing operations include nine plants in Oklahoma with a total inlet capacity of 780 million cubic feet per day. The products extracted from the natural gas stream include marketable ethane, propane, butane and natural gasoline mix. The residue gas remaining after the liquid products have been extracted consists primarily of ethane and methane. In addition to the 66.67 percent interest in the Benedum gas processing plant owned by NuStar Joint Venture, Products also owns the second largest natural gas processing plant in Oklahoma, which is located near Calumet, Oklahoma and has the capacity to process 250 million cubic feet of natural gas per day. Products also owns interests in three other natural gas processing plants in Oklahoma, which have, in the aggregate, the capacity to process approximately 46 million cubic feet of natural gas per day. As stated above, Transok owns and operates nine natural gas processing plants in Oklahoma with an aggregate inlet capacity of 779 million cubic feet per day. All Transok processing plants are cryogenic expander processing plants capable of recovering or rejecting ethane. Product from these plants is delivered into pipeline facilities owned and operated by Koch Industries, Inc. ("Koch").

A portion of the commercial grade propane processed at Products' Calumet facility and two Transok plants are sold on the local market. The other natural gas liquids are delivered into pipeline facilities of Koch and transported to Conway, Kansas (which is one of the nation's largest wholesale markets for natural gas liquids), where they are sold on the spot market. Ethane, which is produced at all of Products' plants except Calumet, is sold under a contract with Equistar Chemicals. This contract expired in February 2000, but is renewable annually on an evergreen basis. Except for a limited number of ethane contracts with polyethylene producers and terminal sales of propane, Transok delivers natural gas liquids via Koch at Conway, Kansas and Mt. Belvieu, Texas, for sale at wholesale prices. Natural gas liquids from the NuStar Joint Venture are sold to the Huntsman Chemicals plant (formerly Rexene Chemicals) in Midland, Texas.

In processing and marketing natural gas liquids, Enogex competes against virtually all other gas processors producing and selling natural gas liquids. Enogex believes it will be able to continue to compete favorably against such companies. With respect to factors affecting the natural gas liquids industry generally, as the price of natural gas liquids fall without a corresponding decrease in the price of natural gas, it may become uneconomical to extract certain natural gas liquids. As to factors affecting Enogex specifically, the volume of natural gas processed at their plants is dependent upon the volume of natural gas gathered by Enogex and other gatherers through their pipeline systems. Generally, if the volume of natural gas gathered increases, then the volume of liquids extracted by Enogex should also increase.

Marketing. Enogex's natural gas marketing is conducted through Resources. Resources serves both producers and consumers of natural gas by buying natural gas at pooling points both on and off the Enogex pipeline system and reselling to interstate pipelines, end-users or downstream purchasers both within and outside Oklahoma. Resources has placed emphasis on the purchase and sale of volumes of gas moving on the Enogex pipeline system in order to enhance utilization of pipeline capacity. During 1999, Resources sold approximately 805 billion Btu of natural gas per day, of which about 37 percent moved on the Enogex pipeline system.

Resources purchases and sells gas under long-term contracts, as well as in the "spot" market. In response to changes currently taking place in the gas industry, Resources has been de-emphasizing its short-term markets, and an increasing proportion of its revenues are earned pursuant to long-term sales contracts. However, short-term or "spot" sales of natural gas will continue to play a critical role in overall strategy because they provide an important source of market intelligence, while serving a portfolio balancing function. Price risk on extended term gas purchase or sales contracts entered into by Resources is hedged on the NYMEX futures exchange as a matter of corporate policy. Resources markets natural gas developed by Exploration when volumes are sufficiently concentrated to justify Resources marketing these volumes directly instead of through the property operator. Other services provided include energy forward price evaluations and centralized corporate commodity price risk assessment.

In its marketing business, Resources encounters competition from other natural gas transporters and marketers and from other available alternative energy sources. The effect of competition from alternative energy sources is dependent upon the availability and cost of competing supply sources. Resources competes with all major suppliers of natural gas in the geographic markets they serve. For natural gas, those geographic markets are primarily the areas served by pipelines with which Enogex, Transok or NOARK are interconnected. Although the price of the gas is an important factor to a buyer of natural gas from Resources, the primary factor is the total cost (including transportation fees) that the buyer must pay. Natural gas transported for Resources by Enogex, Transok or NOARK are billed at the same rates charged for comparable third-party transportation.

In 1998, Resources successfully initiated wholesale electric power purchase and reselling operations. Resources received market-based rate authority in 1997 from the FERC. See "Electric Operations - Regulation and Rates." During 1999, Resources had approximately 2.0 million Mwh of power sales. Resources acts as OG&E's natural gas purchasing arm for the natural gas fuel requirements of the OG&E power stations. Additionally, since March 1999, virtually all of the Company's surplus power sales activity has been performed by Resources.

Exploration and Production. Exploration 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 also has interests in Oklahoma, Utah, Texas, Indiana, Mississippi and Louisiana. As of December 31, 1999, Exploration had interests in 240 active wells and estimated proved reserves of 95,086 MMcfe. The standardized measure of discounted future net cash flow with related Section 29 tax credits of Exploration's proved reserves was $56.5 million at December 31, 1999. During the fourth quarter of 1998, Exploration (through Resources) initiated a program of hedging the future gas selling price on a portion of its lease production through commodity futures contracts to cushion against unfavorable monthly price swings.

FINANCE AND CONSTRUCTION

The Company generally meets its cash needs through internally generated funds, short-term borrowings and permanent financing. Cash flows from operations have enabled the Company to internally generate the required funds to satisfy construction expenditures. Additional capital expenditures, primarily to fund the acquisition of Transok, were funded temporarily through revolving credit.

Management expects that internally generated funds will be adequate over the next three years to meet the Company's anticipated construction expenditures. The primary capital requirements for 2000 through 2002 are estimated as follows:

(dollars in millions)	2000	2001	2002
Electric utility construction expenditures including AFUDC............	$109.0	$100.0	$100.0
Non-utility construction expenditures and pending acquisitions................	141.9	71.3	50.6
Maturities of long-term debt.............	169.0	2.0	115.0
Total................................	$419.9	$173.3	$265.6

The three-year estimate includes expenditures for construction of new facilities to meet anticipated demand for service, to replace or expand existing facilities in both its electric and non-utility businesses, to fund pending acquisitions (including any related capital expenditures), and to some extent, for satisfying maturing debt. Approximately $1.0 million of the Company's construction expenditures budgeted for 2000 are to comply with environmental laws and regulations. OG&E's construction program was developed to support an anticipated peak demand growth of one to two percent annually and to maintain minimum capacity reserve margins as stipulated by the Southwest Power Pool. See "Electric Operations - Rate Structure, Load Growth and Related Matters."

OG&E intends to meet its customers' increased electricity needs during the foreseeable future primarily by maintaining the reliability and increasing the utilization of existing capacity. OG&E's current resource strategy includes the reactivation of existing plants and the addition of peaking resources. OG&E does not anticipate the need for another base-load plant in the foreseeable future.

The Company will continue to use short-term borrowings to meet temporary cash requirements. OG&E has the necessary regulatory approvals to incur up to $400 million in short-term borrowings at any one time. At December 31, 1999, the Company had in place a line of credit for up to $200 million, of which $100 million was to expire on January 15, 2000, and the remaining $100 million was to expire on January 15, 2004. In January 2000, the Company's line of credit was increased to $300 million; with $200 million to expire on January 15, 2001 and $100 million to expire on January 15, 2004. The maximum amount of outstanding short-term borrowings during 1999 was $198.9 million.

In October 1995, OG&E changed its primary method of long-term debt financing from issuing first mortgage bonds under its First Mortgage Bond Trust Indenture to issuing Senior Notes under a new Indenture (the "Senior Note Indenture"). Each series of Senior Notes issued under the Senior Note

Indenture was secured in essence by a series of first mortgage bonds (the "Back-up First Mortgage Bonds"), subject to the condition that, upon retirement or redemption of all first mortgage bonds issued prior to October 1995 (the "Prior First Mortgage Bonds"), each series of Back-up First Mortgage Bonds would automatically be canceled. In April 1998, all of the Prior First Mortgage Bonds were redeemed or retired with the result that no first mortgage bonds remain outstanding. OG&E has cancelled its First Mortgage Bond Trust Indenture and caused the related first mortgage lien on substantially all of its properties to be discharged and released. OG&E expects to have more flexibility in future financings under its Senior Note Indenture than existed under the First Mortgage Bond Trust Indenture.

In accordance with the requirements of the PURPA (see "Electric Operations - Regulation and Rates - National Energy Legislation"), OG&E is obligated to purchase 110 megawatts of capacity annually from Smith Cogeneration, Inc., 320 megawatts annually from Applied Energy Services, Inc., another qualified cogeneration facility and up to 110 megawatts of capacity from Mid-Continent Power Company ("MCPC"). OG&E also has agreed to purchase energy not needed by the Sparks Regional Medical Center from its nominal seven megawatt cogeneration facility.

The Company's financial results continue to depend to a large extent upon the tariffs OG&E charges customers and the actions of the regulatory bodies that set those tariffs, the amount of energy used by OG&E's customers, the cost and availability of external financing and the cost of conforming to government regulations.

ENVIRONMENTAL MATTERS

The Company's management believes 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 $44.4 million during 2000, compared to approximately $43.5 million utilized in 1999. Approximately $1.0 million of the Company's construction expenditures budgeted for 2000 are to comply with environmental laws and regulations. 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.

As required by Title IV of the Clean Air Act Amendments of 1990 ("CAAA"), OG&E has completed installation and certification of all required continuous emissions monitors ("CEMs") at its generating stations. OG&E submits emissions data quarterly to the Environmental Protection Agency ("EPA") as required by the CAAA. Phase II sulfur dioxide ("SO2") emission requirements will affect OG&E beginning in the year 2000. Based on current information, OG&E believes it can meet the SO2 limits without additional capital expenditures. In 1999, OG&E emitted 54,845 tons of SO2.

With respect to the nitrogen oxide ("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 1999 was 0.37 lbs/mmbtu.

OG&E has submitted all of its required Title V permit applications. As a result of the Title V Program, OG&E paid approximately $0.4 million in fees in 1999.

Other potential air regulations have emerged that could impact OG&E. By December 15, 2000 the EPA is expected to decide whether or not to regulate mercury emissions from coal-fired utility boilers. If the decision is made to regulate them, limits on the amount of mercury emitted are expected to be proposed by December 2003 with company compliance required by 2008.

In 1997, EPA finalized revisions to the ambient ozone and particulate standards. However the standards were challenged in court and the ozone standard was subsequently remanded back to EPA for further consideration. EPA has appealed the decision to the US Supreme Court. If the proposed standard is upheld then it is likely that Tulsa and Oklahoma counties will fail to meet the new standard for ozone. In addition, EPA projects that Muskogee, Kay, Tulsa and Comanche counties in Oklahoma would fail to meet the standard for particulate matter. If reductions are required in Muskogee, Kay and Oklahoma counties, significant capital expenditures could be required by OG&E.

EPA has issued regulations concerning regional haze. This regulation is 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. Emissions of sulfates and nitrate aerosols (both emitted from coal-fired boilers) can lead to the degradation of visibility. It is possible that controls on sources hundreds of miles away from the affected area may be required. EPA and the states will perform studies of the areas to determine what if any controls are needed in Oklahoma. Both Sooner and Muskogee Generating Stations could face significant capital expenditures if reductions are required.

In December 1997, the United States was a signatory to the Kyoto Protocol for the reduction of greenhouse gases that contribute to global warming. The U.S. committed to a 7 percent reduction from the 1990 levels. If the Senate ratifies the Kyoto Protocol, this reduction could have a significant impact on OG&E's use of coal as a boiler fuel. Based on current load and fuel budget projections, a 7 percent reduction of greenhouse gases would require OG&E to substantially increase gas burning in the year 2008 and to significantly reduce its use of coal as a boiler fuel. Since there are numerous issues which will affect how this reduction would be implemented, if at all, the cost to the Company to comply with this reduction cannot be established at this time, but is expected to be substantial.

The Company has and will continue to seek new pollution prevention opportunities and to evaluate the effectiveness of its waste reduction, reuse and recycling efforts. In 1999, the Company obtained refunds of approximately $355,225 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 reuse of existing materials. Similar savings are anticipated in future years.

OG&E has received renewal of all of its Oklahoma Pollution Discharge Elimination System ("OPDES") permits for all facilities except one, which is pending regulatory action. All of the renewed permits issued to date offer greater operational flexibility than those in the past. In addition, OG&E has made application for a new OPDES permit to cover Gas Turbine generating units currently being constructed at one of our existing power plants. No problems are foreseen in the ultimate regulatory approval of this permit.

OG&E requested that the State agency responsible for the development of Water Quality Standards remove the agriculture beneficial use classification from one of its cooling water reservoirs. Without removal of this classification, one OG&E facility could be subjected to costly treatment and/or facility reconfiguration requirements. The State has approved the request and EPA, in their review of Oklahoma's Water Quality Standards, has not disapproved this issue.

OG&E remains a party to two separate actions brought by the EPA concerning cleanup of disposal sites for hazardous and toxic waste. See "Item 3. Legal Proceedings".

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. One site has been identified as having been contaminated by historical operations. Remedial options based on the future use of this site are being pursued with appropriate regulatory agencies. The cost of these actions has not had and is not anticipated to have a material adverse impact on the Company's financial position or results of operations.

EMPLOYEES

The Company and its subsidiaries had 3,074 employees at December 31, 1999.

ITEM 2. PROPERTIES.

OG&E owns and operates an interconnected electric production, transmission and distribution system, located in Oklahoma and western Arkansas, which includes eight active generating stations with an aggregate active capability of 5,513 megawatts. The following table sets forth information with respect to present electric generating facilities, all of which are located in Oklahoma:

Station & Unit		Fuel	Year Installed	Unit Capability (Megawatts)	Station Capability (Megawatts)
Seminole	1	Gas	1971	517.0	
	2	Gas	1973	505.0	
	3	Gas	1975	496.0	1,518
Muskogee	3	Gas	1956	171.0	
	4	Coal	1977	515.0	
	5	Coal	1978	478.0	
	6	Coal	1984	488.0	1,652
Sooner	1	Coal	1979	500.0	
	2	Coal	1980	512.0	1,012
Horseshoe	6	Gas	1958	171.0	
Lake	7	Gas	1963	234.0	
	8	Gas	1969	390.0	795
Mustang	1	Gas	1950	58.0	Inactive
	2	Gas	1951	57.0	Inactive
	3	Gas	1955	118.0	
	4	Gas	1959	239.0	
	5	Gas	1971	63.0	420
Conoco	1	Gas	1991	32.0	
	2	Gas	1991	31.0	63
Arbuckle	1	Gas	1953	74.0	Inactive
Enid	1	Gas	1965	11.0	
	2	Gas	1965	8.0	
	3	Gas	1965	12.0	
	4	Gas	1965	12.0	43
Woodward	1	Gas	1963	10.0	10
Total Active Generating Capability (all stations)					5,513

At December 31, 1999, OG&E's transmission system included: (i) 65 substations with a total capacity of approximately 15.5 million kVA and approximately 3,997 structure miles of lines in Oklahoma; and (ii) six substations with a total capacity of approximately 1.9 million kVA and approximately 241 structure miles of lines in Arkansas. OG&E's distribution system included: (i) 301 substations with a total capacity of approximately 4.2 million kVA, 20,205 structure miles of overhead lines, 1,700 miles of underground conduit and 6,924 miles of underground conductors in Oklahoma; and (ii) 30 substations with a total capacity of approximately 737,500 kVA, 1,684 structure miles of overhead lines, 186 miles of underground conduit and 397 miles of underground conductors in Arkansas.

Substantially all of OG&E's electric facilities were previously subject to a direct first mortgage lien under the Trust Indenture securing OG&E's first mortgage bonds. The Trust Indenture and related lien were discharged in April 1998.

Enogex and its subsidiaries own: (i) approximately 8,229 miles of intrastate transmission and gathering lines in the states of Oklahoma and Texas; (ii) 13 natural gas processing plants with a capacity to process over one billion cubic feet per day ("bcfd"), all located in Oklahoma; (iii) 75 percent interest in NOARK Pipeline System L.P., which consists of 925 miles of interstate transmission and gathering pipelines, located in eastern Oklahoma and Arkansas; (iv) an 18 billion cubic feet ("bcf") gas storage field in Oklahoma with a withdrawal capacity of 450 million cubic feet per day ("mmcfd"); (v) leased capacity of five bcf of gas storage in Oklahoma with a withdrawal capacity of 400 mmcfd; (vi) an 80 percent interest in the NuStar Joint Venture, which includes a 66.67 percent interest in the 110 mmcfd capacity Benedum processing plant, a 100 percent interest in a smaller 30 mmcfd by-pass plant, over 185 miles of gathering pipelines and 52 miles of NGL pipeline, all located in the Permian Basin of West Texas; and (vii) 100 percent of the Belvan Corp., which consists of a natural gas processing plant with a capacity of process 15 mmcfd, a sulfur recovery plant, and an eight mile NGL pipeline, and 260 miles of gathering lines in West Texas.

During the three years ended December 31, 1999, the Company's gross property, plant and equipment additions approximated $1.4 billion and gross retirements approximated $132.6 million. These additions were provided by internally generated funds from operating cash flows, permanent financing and short-term borrowings. The additions during this three-year period amounted to approximately 26.3 percent of total property, plant and equipment at December 31, 1999.

ITEM 3. LEGAL PROCEEDINGS.

1. On July 8, 1994, an employee of OG&E filed a lawsuit in state court against OG&E in connection with OG&E's VERP. The case was removed to the U.S. District Court in Tulsa, Oklahoma. On August 23, 1994, the trial court granted OG&E's Motion to Dismiss Plaintiff's Complaint in its entirety.

On September 12, 1994, Plaintiff, along with two other Plaintiffs, filed an Amended Complaint alleging substantially the same allegations, which were in the original complaint. The action was filed as a class action, but no motion to certify a class was ever filed. Plaintiffs want credit, for retirement purposes, for years they worked prior to a pre-ERISA (1974) break in service. They allege violations of ERISA, the Veterans Reemployment Act, Title VII, and the Age Discrimination in Employment Act. State law claims, including one for intentional infliction of emotional distress, are also alleged.

On October 10, 1994, Defendants filed a Motion to Dismiss Counts II, IV, V, VI and VII of Plaintiffs' Amended Complaint. With regard to Counts I and III, Defendants filed a Motion for Summary Judgment on January 18, 1996. On September 8, 1997, the United States Magistrate Judge recommended the Defendant's motions to dismiss and for summary judgment should be granted and that the case be dismissed in its entirety and judgment entered for OG&E. The United States District Judge accepted the recommendation of the Magistrate and entered judgment for OG&E. Plaintiffs filed an appeal with the Tenth Circuit Court of Appeals. In August 1999, the Tenth Circuit affirmed in all respects the District Courts' decision dismissing Plaintiff's case and entering judgment for OG&E. Since the Plaintiffs have failed to file a timely writ of certiorari to the U.S. Supreme Court, the Company considers this case closed.

2. On January 11, 1993, OG&E received a Section 107 (a) Notice Letter from the EPA, Region VI, as authorized by the CERCLA, 42 USC Section 9607 (a), concerning the Double Eagle Refinery Superfund Site located at 1900 NE First Street in Oklahoma City, Oklahoma. The EPA has named OG&E and 45 others as PRPs. Each PRP could be held jointly and severally liable for remediation of this site.

On February 15, 1996, OG&E elected to participate in the de minimis settlement of EPA's Administrative Order on Consent. This would limit OG&E's financial obligation and also would eliminate its involvement in the design and implementation of the site remedy. A third party is currently contesting OG&E's participation as a de minimis party. Regardless of the outcome of this issue, OG&E believes that its ultimate liability for this site will not be material primarily due to the limited volume of waste sent by OG&E to the site.

3. As previously reported, on September 18, 1996, Trigen-Oklahoma City Energy Corporation ("Trigen") sued OG&E in the United States District Court, Western District of Oklahoma, Case No. CIV-96-1595-M. Trigen alleged six causes of action: (i) monopolization in violation of Section 2 of the Sherman Act; (ii) attempt to monopolize in violation of Section 2 of the Sherman Act; (iii) acts in restraint of trade in violation of Oklahoma law, 79 O.S. 1991, 1; (iv) discriminatory sales in violation of 79 O.S. 1991, 4; (v) tortious interference with contract; and (vi) tortious interference with a prospective economic advantage. On December 21, 1998, the jury awarded Trigen in excess of $30 million in actual and punitive damages. On February 19, 1999, the trial court entered judgment in favor of Trigen as follows: (i) $6.8 million for various antitrust violations, (ii) $4 million for tortious interference with an existing contract, (iii) $7 million for tortious interference with a prospective economic advantage and (iv) $10 million in punitive damages. The trial judge, in a companion order, acknowledged that the portions of the judgment could be duplicative, that the antitrust amounts could be tripled and that parties should address these issues in their post-trial motions. On March 5, 1999, OG&E filed its post trial motions requesting judgment in its favor as a matter of law, a new trial and a reduction in amount of any judgment to eliminate duplication of damages. On January 25, 2000, a trial judge rejected OG&E's post-trial motions to reverse the jury verdict or to grant OG&E a new trial. The judge did, however, reduce the original $30 million judgment against OG&E to $20 million. On February 4, 2000, OG&E filed a notice of appeal. In addition, Trigen has filed a motion seeking attorneys' fees and costs in an amount over $3 million. Trigen will not be entitled to attorneys' fees or costs unless it prevails on appeal. While the outcome of the appeal is uncertain, legal counsel and management believe that it is not probable that Trigen will ultimately succeed in preserving the verdicts or judgment. Accordingly, the Company has not accrued any loss associated with the damages awarded. The Company believes that the ultimate resolution of this case will not have a material adverse effect on the Company's consolidated financial position or results of operations.

4. 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, eighteen 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 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.

5. On February 19, 1998, Enogex was sued by Melvin Scoggin and Oak Tree Resources, LLC, in the District Court of Oklahoma County, State of Oklahoma, for alleged breach of contract, fraud, breach of fiduciary duty, misappropriation and unjust enrichment arising from communications that allegedly created agreements regarding oil and gas exploration activities. Plaintiffs' seek damages in excess of $25 million. Enogex filed an answer denying Plaintiffs' allegations and various motions for summary judgment. On October 20, 1999, and October 25, 1999, the trial judge granted Enogex's motions for summary judgment and entered judgment in favor of Enogex on all claims raised by the Plaintiffs. The time for Plaintiffs to appeal the trial court's decision has not expired as of the date of this report. The Company continues to believe that this case is without merit.

6. United States of America ex rel., Jack J. Grynberg v Enogex Inc., Enogex Services Corporation (now, Resources) 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. Plaintiff's action is a qui tam action under the False Claims Act. Jack J. Grynberg, as individual Relator on behalf of the United States Government, Plaintiff, alleges: (i) each of the named Defendants have improperly and 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; (e) interest, costs and attorneys' fees. Plaintiff has filed over 70 other cases naming over 300 other defendants in various Federal Courts across the country containing nearly identical allegations.

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 or any of the other Grynberg qui tam actions.

On November 16, 1999, the Multidistrict Litigation Panel ("MDL Panel") entered its order 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.

On November 17, 1999, the Company filed a motion to dismiss, seeking: (i) a stay of discovery until after the dispositive motions are resolved; and (ii) dismissal of the complaint on various basis under the Federal Rules of Civil Procedure. A number of other defendants adopted the Company's pleadings or filed similar motions. On December 22, 1999, the Company joined a number of other defendants in filing Defendants' Statement of Points and Authorities regarding discovery issues. Grynberg's responses to all motions to dismiss were filed on January 14, 2000, and the Company's reply and those of other defendants were filed on February 14, 2000. A hearing on the motions to dismiss was held on March 17, 2000.

On December 15, 1999, the Court held a Pretrial conference for all MDL-consolidated cases. A number of issues were discussed at such Pretrial conference and the above-listed schedule was established. All discovery is stayed until further order of the Court.

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.

7. On September 28, 1999, the Company was served with an Amended Class Action Petition filed in United States District Court, State of Kansas by Quinque Operating Company, on behalf of itself and others, alleging approximately 200 defendants, including OG&E, Enogex and two subsidiaries of Enogex, including Transok, have improperly and intentionally mismeasured gas (both volume and Btu content) purchased from all lands in the United States except from federal and Indian lands. Plaintiffs claim (i) underpayment by the Company and all other Defendants of gas royalties claimed to be owed to the Plaintiffs and the punitive class; (ii) breach of contract; (iii) negligence or intentional misrepresentation; (iv) civil conspiracy; (v) fraud; and (vi) breach of fiduciary duty. Plaintiffs seek the following damages: a) actual damages in excess of $75,000; b) punitive damages; c) certification of the class; and d) injunction to prevent mismeasurement in the future.

On October 5, 1999, the Company filed its notice with the MDL Panel advising the MDL Panel that this case involved the same measurement issues and was a potential tag-along to the Grynberg matter discussed in Item No. 6 above. Plaintiffs opposed the MDL Panel transfer. The MDL Panel has scheduled a hearing on the transfer issue for March 30, 2000.

On October 28, 1999, the Company and a number of the Defendants filed a "Joint Request for Extension or Enlargement of Time to Answer or Otherwise Respond to the First Amended Class Action filed. On December 1, 1999, the Court granted the Company, and all other Defendants who requested relief, until thirty (30) days after the Court rules on Plaintiff's Motion to Remand for the Company to answer or otherwise plead in this case. There has been no ruling to date on the Plaintiffs' Motion to Remand.

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.

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 March 15, 2000:

Name	Age	Title
Steven E. Moore	53	Chairman of the Board, President and Chief Executive Officer
Al M. Strecker	56	Executive Vice President and Chief Operating Officer
Roger A. Farrell	47	President and Chief Executive Officer - Enogex Inc.
James R. Hatfield	42	Senior Vice President, Chief Financial Officer and Treasurer
Jack T. Coffman	56	Senior Vice President - Power Supply - OG&E
Melvin D. Bowen, Jr.	58	Vice President - Power Delivery - OG&E
Michael G. Davis	50	Vice President - Marketing and Customer Care
Irma B. Elliott	61	Vice President and Corporate Secretary
Steven R. Gerdes	43	Vice President - Shared Services
David J. Kurtz	38	Vice President - Business Development
Donald R. Rowlett	42	Vice President and Controller
Don L. Young	59	Controller Corporate Audits

No family relationship exists between any of the Executive Officers of the Registrant. Messrs. Moore, Strecker, Hatfield, Davis, Gerdes, Kurtz, Rowlett, Young and Ms. Elliott are also officers of OG&E. Each Officer is to hold office until the Board of Directors meeting following the next Annual Meeting of Shareowners, currently scheduled for May 18, 2000.

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	1996-Present:	Chairman of the Board, President and Chief Executive Officer
	1995-1996:	President and Chief Operating Officer - OG&E
	1995:	Senior Vice President - Law and Public Affairs - OG&E
Al M. Strecker	1998-Present:	Executive Vice President and Chief Operating Officer
	1996-1998:	Senior Vice President
	1995-1996:	Senior Vice President - Finance and Administration - OG&E
Roger A. Farrell	1998-Present:	President and Chief Executive Officer - Enogex Inc.
	1997-1998	Executive Vice President - Enogex Inc.
	1995-1997	Vice President - Business Development - Enogex Inc.
James R. Hatfield	1999-Present:	Senior Vice President, Chief Financial Officer and Treasurer
	1997-1999:	Vice President and Treasurer
	1995-1997:	Treasurer - OG&E
Jack T. Coffman	1999-Present:	Senior Vice President - Power Supply - OG&E
	1995-1999:	Vice President - Power Supply - OG&E
Melvin D. Bowen, Jr.	1995-Present:	Vice President - Power Delivery - OG&E

Michael G. Davis	1998-Present:	Vice President - Marketing and Customer Care
	1995-1998:	Vice President - Marketing and Customer Services - OG&E
Irma B. Elliott	1996-Present:	Vice President and Corporate Secretary
	1995-1996:	Corporate Secretary - OG&E
Steven R. Gerdes	1998-Present:	Vice President - Shared Services
	1997-1998:	Director - Shared Services
	1997:	Manager - Enterprise Support
	1995-1997:	Manager - Purchasing and Material Management - OG&E
David J. Kurtz	1999-Present:	Vice President - Business Development
	1997-1999:	Vice President - Business Development - Enogex Inc.
	1995-1997:	Director - Gas Supply - Enogex Inc.
Donald R. Rowlett	1999-Present:	Vice President and Controller
	1996-1999:	Controller Corporate Accounting
	1995-1996:	Assistant Controller - OG&E
Don L. Young	1996-Present:	Controller Corporate Audits
	1995-1996:	Controller - OG&E

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.

	1999			1998		
	Dividend Paid	High	Low	Dividend Paid	High	Low
First Quarter	$0.3325	$29 1/16	$22 9/16	$0.3325	$28 15/16	$25 11/16
Second Quarter	0.3325	25 15/16	21 13/16	0.3325	28 15/16	26
Third Quarter	0.3325	24 9/16	21 11/16	0.3325	29 9/16	25 5/8
Fourth Quarter	0.3325	23 3/16	18 1/2	0.3325	30	25 15/16

The number of record holders of Common Stock at December 31, 1999, was 37,233. The book value of the Company's Common Stock at December 31, 1999, was $13.09.

ITEM 6. SELECTED FINANCIAL DATA.

HISTORICAL DATA

	1999	1998	1997	1996	1995
SELECTED FINANCIAL DATA (DOLLARS IN THOUSANDS EXCEPT FOR PER SHARE DATA)					
Operating revenues	$2,172,434	$1,617,737	$1,443,610	$1,387,435	$1,302,037
Operating expenses	1,834,269	1,278,280	1,175,160	1,107,989	1,031,073
Operating income	338,165	339,457	268,450	279,446	270,964
Other income and deductions	3,317	5,758	5,047	97	800
Interest charges	100,279	70,699	66,495	67,984	77,691
Net income	151,259	165,872	132,550	133,332	125,256
Preferred dividend requirements	---	733	2,285	2,302	2,316
Earnings available for common	$ 151,259	$ 165,139	$ 130,265	$ 131,030	$ 122,940
Long-term debt	$1,140,532	$ 935,583	$ 841,924	$ 829,281	$ 843,862
Total assets	$3,921,334	$2,983,929	$2,765,865	$2,762,355	$2,754,871
Earnings per average common share	$ 1.94	$ 2.04	$ 1.61	$ 1.62	$ 1.52
CAPITALIZATION RATIOS					
Common equity	47.20%	52.72%	52.50%	52.26%	51.19%
Cumulative preferred stock	---	---	2.63%	2.68%	2.73%
Long-term debt	52.80%	47.28%	44.87%	45.06%	46.08%
INTEREST COVERAGES					
Before federal income taxes					
(including AFUDC)	3.39X	4.84X	4.11X	4.07X	3.48X
(excluding AFUDC)	3.38X	4.82X	4.10X	4.06X	3.46X
After federal income taxes					
(including AFUDC)	2.50X	3.31X	2.98X	2.94X	2.59X
(excluding AFUDC)	2.49X	3.30X	2.97X	2.93X	2.57X

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS.

MANAGEMENT'S DISCUSSION AND ANALYSIS

OVERVIEW

OGE Energy Corp. (the "Company") reported earnings of $1.94 a share in 1999, a 4.9 percent decrease from $2.04 a share in 1998. The decrease was primarily the result of lower revenues at Oklahoma Gas and Electric Company ("OG&E") due to milder weather in the OG&E service area, lower recoveries under the Generation Efficiency Performance Rider ("GEP Rider") and less revenue from sales to other utilities and power marketers ("off-system sales"). The GEP Rider, which was implemented in 1997, allows OG&E to retain part of the fuel savings achieved through cost efficiencies and is discussed in more detail below. The decrease in earnings was partially offset by significantly higher earnings at the Company's Enogex Inc. natural gas pipeline business, and benefits resulting from the Company repurchasing 3 million shares of its common stock on January 15, 1999.

The 1998 increase in earnings to $2.04 a share from $1.61 a share in 1997 was primarily the result of higher revenues at OG&E due to warmer weather, the GEP Rider, higher margin off-system sales, customer growth and lower operation and maintenance expense. The increase in earnings in 1998 was partially offset by lower earnings at Enogex Inc. and its subsidiaries ("Enogex").

				Percent Change From Prior Year	
(THOUSANDS EXCEPT PER SHARE AMOUNTS)	1999	1998	1997	1999	1998
Operating revenues......................	$2,172,434	$1,617,737	$1,443,610	34.3	12.1
Earnings available for common stock.....	$ 151,259	$ 165,139	$ 130,265	(8.4)	26.8
Average shares outstanding..............	77,916	80,772	80,745	(3.5)	---
Earnings per average common share.......	$ 1.94	$ 2.04	$ 1.61	(4.9)	26.7
Earnings per average common share - assuming dilution.....................	$ 1.94	$ 2.04	$ 1.61	(4.9)	26.7
Dividends paid per share................	$ 1.33	$ 1.33	$ 1.33	---	---

The Company serves as the parent holding company to OG&E, Enogex and OGE Energy Capital Trust I, a financing trust established in 1999. This holding company structure is intended to provide greater flexibility, allowing the Company to take advantage of opportunities in an increasingly competitive business environment and to clearly separate the Company's electric utility business from its non-utility businesses. Because OG&E is the Company's principal subsidiary, the Company's financial results and condition are substantially dependent at this time on the financial results and condition of OG&E.

The following discussion and analysis presents factors which had a material effect on the operations and financial position of the Company and its subsidiaries during the last three years and should be read in conjunction with the Consolidated Financial Statements and Notes thereto. Average shares outstanding and all per share amounts have been restated to reflect the two-for-one stock split that occurred in June 1998. Trends and contingencies of a material nature are discussed to the extent known and considered relevant.

The dividend payout ratio (expressed as a percentage of earnings available for common shareholders) was 69 percent in 1999 as compared to 65 percent in 1998, within the Company's desired dividend payout ratio of 75 percent or below based on the current business environment. Future dividend action will be dependent primarily on two factors. First, the appropriate payout ratio will be determined by the pace and structure of the deregulation of the electric utility business. Second, the payout rates will continue to be based on current and anticipated operating results. On a positive note, the Staff of the Oklahoma Corporation Commission reported in OG&E's recent performance-based rate filing that OG&E's electric rates as a whole were appropriate and did not warrant a general rate review, which in the Company's judgment, virtually eliminates the likelihood of an adverse general rate case in Oklahoma prior to the start of deregulation.

The Company's regulated utility business has been and will continue to be affected by competitive changes to the utility industry. Significant changes already have occurred in the wholesale electric markets at the Federal level and significant changes are expected at the retail level in the states served by OG&E. In Oklahoma, legislation was passed in 1997 to provide for the orderly restructuring of the electric industry with the goal to provide retail customers with the ability to choose their generation suppliers by June 30, 2002. In April 1999, Arkansas became the 18th state to pass a law calling for restructuring of the electric utility industry at the retail level. The new law targets customer choice of electricity providers by January 1, 2002. These developments at the federal and state levels are described in more detail below under "Regulation; Competition."

On July 1, 1999, the Company, through Enogex, completed its largest acquisition in its history by acquiring Tejas Transok Holding, L.L.C. and its subsidiaries ("Transok"), a gatherer, processor and transporter of natural gas in Oklahoma and Texas. Transok's principal assets include approximately 4,900 miles of natural gas pipelines in Oklahoma and Texas with a capacity of approximately 2.6 billion cubic feet per day and 18 billion cubic feet of underground natural gas storage. Transok also owns 9 gas processing plants, which produced approximately 26,000 barrels per day of natural gas liquids in 1998. Enogex purchased Transok for $710.3 million, which includes assumption of $173 million of long-term debt. Integration of Transok's operations continues on schedule and operation of the combined natural gas pipelines turned accretive to OGE Energy's earnings in the fourth quarter, earlier than previously expected. Transok posted net income of $3.8 million in the fourth quarter of 1999. While $20 million in synergies were expected with the acquisition, about $22 million in synergies already have been realized or identified and further improvement is possible in the coming year.

Forward-Looking Statements

Except for the historical statements contained herein, the matters discussed in the following discussion and analysis, 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", "estimate", "objective", "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 their impact on capital expenditures; business conditions in the energy industry; competitive factors; unusual weather; regulatory decisions; and the other risk factors listed in the reports filed by the Company with the Securities and Exchange Commission.

RESULTS OF OPERATIONS

REVENUES

(THOUSANDS)	1999	1998	1997	Percent Change From Prior Year 1999	Percent Change From Prior Year 1998
Sales of electricity to OG&E customers...	$1,258,950	$1,274,643	$1,168,663	(1.2)	9.1
Off-system sales........................	27,894	37,435	23,027	(25.5)	62.6
Enogex..................................	885,512	304,694	251,575	190.6	21.1
Miscellaneous...........................	78	965	345	(91.9)	179.4
Total operating revenues..............	$2,172,434	$1,617,737	$1,443,610	34.3	12.1
System megawatt-hour sales..............	23,468,130	23,642,599	22,182,992	(0.7)	6.6
Off-system megawatt-hour sales...........	374,027	727,601	1,201,933	(48.6)	(39.5)
Total megawatt-hour sales.............	23,842,157	24,370,200	23,384,925	(2.2)	4.2

In 1999, approximately 59 percent of the Company's revenues consisted of regulated sales of electricity as a public utility, while the remaining 41 percent were provided by the non-utility operations of Enogex. Revenues from sales of electricity are somewhat seasonal, with a large portion of the Company's annual electric revenues occurring during the summer months when the electricity needs of its customers increase. Enogex's primary operations consist of gathering and processing natural gas, transporting natural gas through its pipelines in Oklahoma, Arkansas and Texas for various customers (including OG&E), marketing electricity, natural gas and natural gas liquids and investing in the drilling for and production of natural gas and crude oil. Actions of the regulatory commissions that set OG&E's electric rates will continue to affect the Company's financial results. The commissions also have the authority to examine the appropriateness of OG&E's recovery from its customers of fuel costs, which include the transportation fees that OG&E pays Enogex for transporting natural gas to OG&E's generating units. See "Regulation; Competition" and Note 11 of Notes to Consolidated Financial Statements for a discussion of the impact of the Oklahoma Corporation Commission ("OCC") rate order dated February 11, 1997, on these transportation fees.

Operating revenues increased $554.7 million or 34.3 percent during 1999, due to a significant increase in revenue from Enogex. In 1999, Enogex consolidated revenues increased $580.8 million or 190.6 percent, primarily due to a significant increase in sales volumes and rising prices in natural gas and natural gas liquids, the acquisition of Transok in July 1999 ($274.9 million) and increased power marketing sales ($18.5 million).

The increased revenues from Enogex were partially offset by decreased revenues at OG&E. Revenues at OG&E decreased $25.2 million or 1.9 percent primarily due to a decrease in kilowatt-hour sales to OG&E customers ("system sales") and off-system sales, both of which were higher in 1998 because of the record heat of 1998. Lower recoveries under the GEP Rider also contributed to lower revenues at OG&E.

On February 11, 1997, the OCC issued an order (the "1997 Order") that, among other things, effectively lowered OG&E's rates to its Oklahoma retail customers by $50 million annually (based on a test year ended December 31, 1995). Of the $50 million rate reduction, approximately $45 million became effective on March 5, 1997, and the remaining $5 million became effective March 1, 1998. This $50 million rate reduction was in addition to the $15 million rate reduction that was effective January 1, 1995. The 1997 Order also directed OG&E to transition to competitive bidding of its gas transportation requirements, currently met by Enogex, no later than April 30, 2000, and set annual compensation for the transportation services provided by Enogex to OG&E at $41.3 million until competitively-bid gas transportation begins. The $41.3 million included $12.8 million associated with the amortization of the acquisition premium paid by OG&E when it acquired Enogex in 1986. Such premium was fully recovered at March 1, 2000, and as a result, the $41.3 million annual rate will be lowered to $28.5 million annually.

The 1997 Order also established the GEP Rider, which is designed so that when OG&E's average annual cost of fuel per kwh is less than 96.261 percent of the average non-nuclear fuel cost per kwh of certain other investor-owned utilities in the region, OG&E is allowed to collect, through the GEP Rider, one-third of the amount by which OG&E's average annual cost of fuel is less than 96.261 percent of the average of the other specified utilities. If OG&E's fuel cost exceeds 103.739 percent of the stated average, OG&E will not be allowed to recover one-third of the fuel costs above that amount from Oklahoma customers. As explained below, the GEP Rider is currently under review by the OCC.

The fuel cost information used to calculate the GEP Rider is based on fuel cost data submitted by each of the utilities in their Form No. 1 Annual Report filed with the Federal Energy Regulatory Commission ("FERC"). The GEP Rider is revised effective July 1 of each year to reflect any changes in the relative annual cost of fuel reported for the preceding calendar year. For 1999, the GEP Rider contributed approximately $20.8 million to revenues, which was approximately $9.5 million, or approximately $0.07 per share lower than 1998. The current GEP Rider is estimated to positively impact revenue by $13.1 million or approximately $0.10 per share during the 12 months ending June 2000.

During 1998, revenues increased $174.1 million or 12.1 percent. Revenues at OG&E increased $120.4 million or 10.1 percent and at Enogex increased $53.1 million or 21.1 percent. In 1998, OG&E revenues increased primarily due to higher system sales from warmer weather, the GEP Rider, higher off-system sales and customer growth. Kilowatt-hour sales by OG&E to other utilities decreased 39.5 percent in 1998; however, the summer heat drove prices of this off-system electricity to record levels, increasing operating revenues approximately $14.4 million in 1998 and at margins significantly higher than had been experienced in the past. There can be no assurance that such margins on future off-system sales will occur again.

Enogex revenues increased in 1998 primarily as a result of significant increases in the volumes of natural gas sold through its gas marketing activities ($17.2 million), gas transportation services ($7.0 million) and marketing of electricity ($46.3 million). These increases were partially offset by a decrease in natural gas liquids processed and sold ($17.4 million). The increased gas-related revenues were attributable primarily to significantly higher volumes sold which more than offset a decrease in sales prices as such commodity prices were depressed. Other factors contributing to the revenue increases were the acquisitions in 1998 of the Noark Pipeline and Ozark Pipeline, which are described below. The increased electricity-related revenues were due to the expansion in 1998 into the marketing of electricity.

EXPENSES AND OTHER ITEMS

(DOLLARS IN THOUSANDS)	1999	1998	1997	Percent Change From Prior Year 1999	Percent Change From Prior Year 1998
Fuel	$ 309,327	$ 315,194	$ 277,806	(1.9)	13.5
Purchased power	249,203	240,542	222,464	3.6	8.1
Gas and electricity purchased for resale (Enogex)	672,281	216,432	172,764	210.6	25.3
Other operation and maintenance	382,235	305,106	311,337	25.3	(2.0)
Depreciation and amortization	165,041	149,818	142,632	10.2	5.0
Taxes other than income	56,182	51,188	48,157	9.8	6.3
Total operating expenses	$1,834,269	$1,278,280	$1,175,160	43.5	8.8
Total other income (expenses)	$ (96,962)	$ (64,941)	$ (61,448)	49.3	5.7
Provision for income taxes	$ 89,944	$ 108,644	$ 74,452	(17.2)	45.9

Total operating expenses increased $556.0 million or 43.5 percent in 1999, primarily due to a significant increase in sales volumes, rising prices for natural gas and natural gas liquids, the mid-year acquisition of Transok by Enogex, and due to the record numbers and severity of tornadoes that damaged OG&E facilities.

Enogex's gas and electricity purchased for resale pursuant to its energy-marketing operations increased $455.8 million or 210.6 percent for 1999 as compared to $43.7 million or 25.3 percent for 1998. The 1999 increase was due to a significant increase in sales volumes of natural gas, the acquisition of Transok ($173.3 million), and increased power marketing sales. The 1998 increase was due to a significant increase in sales volumes of natural gas which more than offset a decrease in sales prices due to depressed commodity prices, and the expansion into the marketing of electricity.

Other operation and maintenance increased $77.1 million or 25.3 percent in 1999 primarily because of expansion activities at Enogex ($66.1 million) and higher bad debt expense at OG&E ($5.2 million). These increases were partially offset by reduced general corporate expenses ($2.7 million). In 1998, other operation and maintenance decreased $6.2 million or 2.0 percent primarily because of decreases at OG&E in post retirement medical costs ($3.8 million), lower bad debt expense ($3.0 million), completion in February 1997 of the amortization of the $48.9 million regulatory asset established in connection with OG&E's 1994 workforce reduction ($3.8 million) and lower general corporate expenses ($4.5 million). These decreases were partially offset by expansion activities at Enogex ($8.4 million).

In 1999, depreciation and amortization increased $15.2 million or 10.2 percent, reflecting increased depreciable plant, primarily property of Transok ($10.0 million). The increase in 1998 reflects higher levels of depreciable plant.

In 1999, taxes decreased $13.7 million or 8.6 percent primarily due to the reduction of pre-tax income from 1998 to 1999. In 1998, taxes increased $37.2 million or 30.4 percent due to significantly higher pre-tax income.

OG&E's purchased power costs increased $8.7 million or 3.6 percent in 1999 due in large part to emergency purchases in the aftermath of tornadoes, on May 3, 1999 and June 1, 1999, which inflicted heavy damage to the OG&E power supply, transmission and delivery systems. In 1999, the cost of purchased energy per kwh increased 8.7 percent. During 1998, purchased power costs increased $18.1 million or 8.1 percent primarily due to a 13 percent increase in the quantities purchased. During 1998, OG&E also began purchasing power from Mid-Continent Power Company ("MCPC"). Payments to MCPC in 1998 were approximately $8 million. MCPC is a qualified cogeneration facility from which OG&E is required to purchase peaking capacity through 2007. As required by the Public Utility Regulatory Policy Act ("PURPA"), OG&E is currently purchasing power from qualified cogeneration facilities.

Interest expense increased $29.6 million or 41.8 percent in 1999 primarily due to higher interest charges at Enogex and costs associated with increased short-term debt incurred to finance the Transok acquisition.

The increase in interest expense for 1998 was attributable to an increase in the average daily balance of short-term debt. Interest on long-term debt decreased as a result of OG&E refinancing $100.0 million of long-term debt at favorable rates. The resulting savings was partially offset by Enogex issuing $85.7 million of long-term debt.

OG&E's 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 1999, fuel costs decreased $5.9 million or 1.9 percent primarily due to a 3.4 percent decrease in total energy generated which offset a 1.9 percent increase in the average cost of fuel burned for generation of electricity. During 1998, fuel costs increased due to a modest increase in total generation and a slight increase in the average cost of fuel burned.

Variances in the actual cost of fuel used in electric generation and certain purchased power costs, as compared to that component in cost-of-service for ratemaking, are passed through to OG&E's electric customers through automatic fuel adjustment clauses. The automatic fuel adjustment clauses are subject to periodic review by the OCC, the Arkansas Public Service Commission ("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 Enogex, which OG&E seeks to recover through the fuel adjustment clause or other tariffs. Also, as explained below, the OCC Staff recently filed an application to review issues under OG&E's fuel adjustment clause in Oklahoma.

LIQUIDITY AND CAPITAL RESOURCES

The primary capital requirements for 1999 and as estimated for 2000 through 2002 are as follows:

(DOLLARS IN MILLIONS)	1999	2000	2001	2002
Electric utility construction expenditures including AFUDC...........	$101.3	$109.0	$100.0	$100.0
Non-utility construction expenditures and acquisitions.......................	611.6	141.9	71.3	50.6
Maturities of long-term debt.............	17.0	169.0	2.0	115.0
Total................................	$729.9	$419.9	$173.3	$265.6

The Company's primary needs for capital are related to construction of new facilities to meet anticipated demand for OG&E's utility service, to replace or expand existing facilities in OG&E's electric utility business, to replace or expand existing facilities in its non-utility businesses, to acquire new non-utility facilities or businesses and, to some extent, to satisfy maturing debt. The Company generally meets its cash needs through a combination of internally generated funds, short-term borrowings and permanent financing.

1999 CAPITAL REQUIREMENTS AND FINANCING ACTIVITIES

Capital requirements were $729.9 million in 1999. A substantial portion of this was related to the acquisition of Transok. Approximately $2.0 million of the 1999 capital requirements were to comply with environmental regulations. This compares to capital requirements of $261.2 million in 1998, of which $1.0 million was to comply with environmental regulations.

During 1999, the Company's sources of capital were internally generated funds from operating cash flows, permanent financing and short-term borrowings. Variations in accounts receivable and accounts payable are not generally significant indicators of the Company's liquidity, as such variations are primarily attributable to fluctuations in weather in OG&E's service territory, which has a direct effect on sales of electricity.

Short-term borrowings were used during 1999 to meet temporary cash requirements. At December 31, 1999, the Company had outstanding short-term borrowings of $589.1 million, of which approximately $345 million pertained to debt incurred to finance the acquisition of Transok. Through the recent financing described below by Enogex in January 2000, the short-term debt of the Company at January 31, 2000 was $214.1 million.

On July 1, 1999, Enogex completed its acquisition of Transok for approximately $710.3 million, which included assumption of $173 million of long-term debt. The purchase of Transok was temporarily funded through a $560 million revolving bank credit agreement. On October 21, 1999, the Company, through a new financing subsidiary trust, issued $200 million of 8.375 percent trust preferred securities which mature October 15, 2039, and all of the proceeds were used to repay a portion of outstanding borrowings under the revolving bank credit agreement implemented in connection with the acquisition of Transok. To repay the balance of the temporary short-term debt associated with the Transok acquisition

($345 million), on January 14, 2000, Enogex sold $400 million of 8.125 percent senior unsecured notes due January 15, 2010. Enogex entered into a series of interest rate swap agreements to manage interest costs associated with this $400 million issue. The effect of these swap agreements reduces the overall effective interest rate from 8.125 percent to 6.6875 percent during the first year. The balance of the proceeds from the sale was used for general corporate purposes.

On September 1, 1999, Enogex retired $15 million principal amount of 6.75 percent medium-term notes due September 1, 1999. Enogex assumed this debt as a current liability in the acquisition of Transok in July 1999.

On January 15, 1999, the Company repurchased 3 million shares of its Common Stock under an Advanced Share Repurchase Agreement with CIBC Oppenheimer Corp. The purchase price was $80.4 million or $26.8125 per share, the closing price on January 15, 1999. Under the terms of this Advanced Share Repurchase Agreement, the Company agreed to bear the risk of increases and the benefit of decreases on the price of the Common Stock until CIBC Oppenheimer Corp. replaced, through open market purchases or privately negotiated transactions, the shares sold to the Company. The Company previously announced, in November 1998, plans to repurchase up to 6 million shares of its Common Stock over the succeeding two years. However, the Company has chosen not to repurchase any additional shares of its Common Stock at this time and this Advanced Share Repurchase Agreement was terminated on January 14, 2000.

FUTURE CAPITAL REQUIREMENTS

The Company's construction program for the next several years does not include additional base-load generating units. Rather, to meet the increased electricity needs of OG&E's electric utility customers during the foreseeable future, OG&E will concentrate on maintaining the reliability, increasing the utilization of existing capacity and increasing demand-side management efforts. Approximately $1.0 million of the Company's construction expenditures budgeted for 2000 are to comply with environmental laws and regulations.

On October 22, 1998, Enogex entered into an option agreement to purchase two gas turbine generators for use in normal operations for approximately $27.5 million. This agreement was transferred to the Company in September 1999. These two generators produce approximately 50 megawatts of additional peak-load each. The total cost of this project is expected to be approximately $47 million. In August 1999, OG&E announced the reactivation of two of its generators that have been idle for several years. These two generators together produce approximately 115 megawatts of additional peak-load. The total cost of this reactivation project is expected to be approximately $9 million. By June 1, 2000, the Company plans to begin using these four generators, increasing its electric generating capacity by approximately 4 percent.

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, 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 will be adequate over the next three years to meet anticipated construction expenditures, while maturities of long-term debt will require permanent financing, with the amount and type dependent on market conditions at the time. Short-term borrowings will continue to be used to meet temporary cash requirements. The Company has the necessary regulatory approvals to incur up to $400 million in short-term borrowings at any one time. At December 31, 1999, the Company had in place a line of credit for up to $200 million, $100 million was to expire on January 15, 2000, and the remaining $100 million was to expire on January 15, 2004. In January 2000, the Company's line of credit was increased to $300 million, $200 million to expire on January 15, 2001, and $100 million to expire on January 15, 2004.

The Company continues to evaluate opportunities to enhance shareowner returns and achieve long-term financial objectives through acquisitions of non-utility businesses. Permanent financing could be required for such acquisitions.

THE YEAR 2000 ISSUE (A NON-EVENT)

There was a great deal of publicity about the Year 2000 ("Y2K") and the possible problems that information technology systems may have suffered as a result. As the Year 2000 approached, it was feared that date-sensitive systems might recognize the Year 2000 as 1900, or not at all, potentially causing systems, including those of the Company, its customers, suppliers, business partners and neighboring utilities to process critical financial and operational information incorrectly, if they were not Year 2000 ready. A failure to identify and correct any such processing problems prior to January 1, 2000 could have resulted in material operational and financial risks if the affected systems either ceased to function or produced erroneous data. However, the Company was aggressive and did its work well in addressing the risks associated with the Y2K issue. The Company's goal was to minimize the impact of Y2K and our goal was accomplished. Y2K was a non-event.

COSTS OF YEAR 2000 ISSUES

With the Company's mainframe conversion in 1994, the SAP Enterprise Software installations for the financial and customer systems in 1997 and 1999, respectively, and the Energy Management System replacement in 1999, a number of Y2K issues were addressed as part of the Company's normal course upgrades to the information technology systems. These upgrades were already contemplated and provided additional benefits or efficiencies beyond the Year 2000 aspect. Since 1995, the Company has spent approximately $45 million on the mainframe conversion, the initial financial enterprise software systems, the customer care enterprise software installations and the SCADA/EMS replacement.

RISKS OF YEAR 2000 ISSUES

The Company experienced only one minor problem which occurred on New Year's Day when a computer system in OG&E's Outage Management System showed an error that was corrected within an hour with a vendor-provided patch. Although the Company has not experienced any major Y2K problems to date, the Company believes some risks still exist as it may take a full year to identify and address all the potential problems in the Company's business systems resulting from Y2K upgrades, corrections and patches.

CONTINGENCIES

The Company through its subsidiaries is defending various claims and legal actions, including environmental actions, which are common to its operations. For a further discussion of these actions, including a lawsuit involving Trigen-Oklahoma City Energy Corporation, see Note 10 of Notes to Consolidated Financial Statements. As to environmental matters, OG&E has been designated as a "potentially responsible party" ("PRP") with respect to two waste disposal sites to which OG&E sent materials. Remediation and required monitoring of one of these sites has been completed. While it is not possible to determine the precise outcome of these matters, in the opinion of management, OG&E's ultimate liability for these sites will not be material.

Beginning in 2000, OG&E will be limited in the amount of sulfur dioxide it will be allowed to emit into the atmosphere. In order to comply with this limit, the Company has contracted for lower sulfur coal. OG&E believes this will allow it to meet this limit without additional capital expenditures. With respect to nitrogen oxides, OG&E continues to meet the current emission standard. However, regulations on regional haze, the possibility of having a new ozone ambient standard that Oklahoma will not be able to meet, and Oklahoma's potential for not being able to meet the new particulate standard, could require further reductions in sulfur dioxide and nitrogen oxides. If this occurs, significant capital expenditures and increased operating and maintenance costs would result.

In 1997, the United States was a signatory to the Kyoto Protocol on global warming. If ratified by the U.S. Senate, this Protocol could have a tremendous impact on the Company's operations, by requiring the Company to significantly reduce the use of coal as a fuel source, since the Protocol would require a seven percent reduction in greenhouse gas emissions below the 1990 level.

The Oklahoma Department of Environmental Quality's CAAA Title V permitting program was approved by the EPA in March 1996. By March of 1997, OG&E had submitted all required permit applications and by December 31, 2000, OG&E expects to have new Title V permits for all of its major source generating stations. Air permit fees for generating stations were approximately $0.4 million in 1999 and are estimated to be about the same in 2000.

By December 15, 2000, the EPA is expected to decide whether or not to regulate mercury emissions from coal-fired utility boilers. If the decision is made to regulate, limits on the amount of mercury emitted are expected to be proposed by December 2003 with the Company's compliance required by 2008. This could result in significant capital and operating expenditures.

COMPETITION; REGULATION

As previously reported, Oklahoma enacted in April 1997 the Electric Restructuring Act of 1997 (the "Act"). Various amendments to the Act were enacted in 1998. If implemented as proposed, the Act will significantly affect OG&E's future operations.

The purpose of the Act, as set forth therein, is generally to restructure the electric utility industry to provide for more competition and, in particular, to provide for the orderly restructuring of the electric utility industry in Oklahoma in order to allow customers to choose their electricity suppliers while maintaining the safety and reliability of the electric system in the state.

The Act directed the Joint Electric Utility Task Force, composed of seven members from the Oklahoma Senate and seven members from the Oklahoma House of Representatives, to undertake a study of all relevant issues relating to restructuring the electric utility industry in Oklahoma and to develop a proposed electric utility framework for Oklahoma. The study was to be delivered in several parts. As a result of the 1998 amendments, the time frame for the delivery of the remaining parts of the study was accelerated to October 1, 1999. This study addressed: (i) technical issues (including reliability, safety, unbundling of generation, transmission and distribution services, transition issues and market power); (ii) financial issues (including rates, charges, access fees, transition costs and stranded costs); (iii) consumer issues (such as the obligation to serve, service territories, consumer choices, competition and consumer safeguards); and (iv) tax issues (including sales and use taxes, ad valorem taxes and franchise fees).

Neither the Oklahoma Tax Commission nor the OCC is authorized to issue any rules on such matters without the approval of the Oklahoma Legislature. Other provisions of the Act (i) authorize the Joint Electric Utility Task Force to retain consultants to study, among other things, the creation of an independent system operator, (ii) prohibit customer switching prior to July 1, 2002, except by mutual consent, (iii) prohibit municipalities that do not become subject to the Act, from selling power outside their municipal limits, except from lines owned on April 25, 1997, (iv) require a uniform tax policy be established by July 1, 2002 and (v) require out-of-state suppliers of electricity and their affiliates who make retail sales of electricity in Oklahoma through the use of transmission and distribution facilities of in-state suppliers to provide equal access to their transmission and distribution facilities outside of Oklahoma. The Act was modified during the 1999 session of the Oklahoma Legislature to clarify certain ambiguities by defining key terms in the Act.

With the completion of the studies described above in October 1999, the Oklahoma legislature is expected to implement additional legislation, which will address many specific issues associated with deregulation. Several bills have already been introduced. While the Company cannot predict the terms of the new legislation, the Company intends to participate actively in the legislative process.

In April 1999, Arkansas became the 18th state to pass a law calling for restructuring of the electric utility industry. The new law targets customer choice of electricity providers by January 1, 2002. The new law also provides that utilities owning or controlling transmission assets must transfer control of such transmission assets to an independent system operator, independent transmission company or regional transmission group, if any such organization has been approved by the FERC. Other provisions of the new law permit municipal electric systems to opt in or out, permit recovery of stranded costs and transition costs and require unbundled rates by July 1, 2000 for generation, transmission, distribution and customer service. As required by the new law, the APSC is in the process of adopting regulations that will implement the new law. The new law and related regulations will significantly affect OG&E's future Arkansas operations. OG&E's electric service area includes parts of western Arkansas, including Fort Smith, the second-largest metropolitan market in the state.

The OCC also has adopted rules that are designed to make the gas utility business in Oklahoma more competitive. These rules do not impact the electric industry. Yet, if implemented, the rules are expected to offer increased opportunities to Enogex's pipeline and related businesses.

These efforts to increase competition in the electric industry at the state level in Oklahoma and Arkansas have been paralleled and even surpassed by efforts at the federal level to increase competition in the wholesale markets for electricity. In October 1992, the National Energy Policy Act of 1992 ("Energy Act") was enacted. Among many other provisions, the Energy Act is designed to promote competition in the development of wholesale power generation in the electric utility industry. It exempts a new class of independent power producers ("IPPs") from regulation under the Public Utility Holding Company Act of 1935 and allows the FERC to order wholesale "wheeling" by public utilities to provide utility and non-utility generators access to public utility transmission facilities.

Within four years of the enactment of the Energy Act, FERC issued Order 888 and Order 889 to facilitate third-party utilization of the transmission grid as the vehicle for developing a more competitive wholesale bulk power market. Order 888 requires all transmission owners to (1) offer comparable open-access transmission service for wholesale transactions under a tariff of general applicability on file at FERC and (2) take transmission service for their own wholesale sales under their open-access tariff. Order 889 requires electric utilities to functionally separate their transmission and reliability functions from their wholesale power marketing functions. In this connection, Order 889 required electric utilities to develop and maintain an Open Access Same-Time Information System ("OASIS") to ensure that transmission customers have access to transmission information, through electronic means, that will enable them to obtain open-access transmission service on a basis comparable to a transmitting utility's own use of its system.

The Energy Act, Orders 888 and 889, and other FERC policies and initiatives have had a tremendous impact on the development of a competitive wholesale power market. Utilities, including OG&E, have increased their own in-house wholesale marketing efforts and the number of entities with whom they trade. Moreover, power marketers are an increasingly important presence in the industry. These entities typically arbitrage wholesale price differentials by buying power produced by others in one market and selling it in another. IPPs 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, almost all of it from IPPs.

Notwithstanding these developments in the wholesale power market, FERC recognized that impediments remained to the achievement of fully competitive wholesale markets including: (1) engineering and economic inefficiencies inherent in the current operation and expansion of the transmission grid and (2) continuing opportunities for transmission owners to discriminate in the operation of their transmission facilities in favor of their own or affiliated power marketing activities. Whereas FERC in the past only encouraged utilities to join and place their transmission systems under the operational control of independent system operators ("ISOs"), FERC, issued Order 2000 on December 20, 1999, its final rule on regional transmission organizations ("RTOs"). Order 2000 sets out a timetable for every jurisdictional utility (including OG&E) to either join in an RTO filing, or, alternatively, to submit a filing by October 15, 2000 describing its efforts to join in an RTO, the reasons for not participating in an RTO proposal and any obstacles to participation, and its plans for further work toward participation. Public utilities that have already transferred control of their facilities to a FERC-approved RTO must file with FERC by January 15, 2001, a statement explaining, among other things, how such RTO has the minimum characteristics and performs the minimum functions identified by FERC in the final rule. These minimum characteristics and functions are 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, FERC stressed that Order 2000 does not preclude it from requiring RTO participation.

OG&E is a member of the Southwest Power Pool ("SPP"), the regional reliability organization for Oklahoma, Arkansas, Kansas, Louisiana, Missouri and part of 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. OG&E presently intends to meet its obligations to transfer operational control of its transmission system to an RTO under Order 2000 and under the new Arkansas deregulation law through the SPP. The SPP has asked for FERC recognition as an ISO consistent with FERC's ISO guidelines in its Order 888 and related provisions in Order 2000. The transfer of operational control of OG&E's transmission system to a FERC-approved RTO is not expected to impact significantly OG&E's financial results. Yet, it is expected to increase the markets in which OG&E can sell power at wholesale and, at the same time, to increase competition in such wholesale markets. As a low-cost producer of electricity with two of the most efficient power plants in the country, OG&E expects to remain a competitive supplier of electricity.

As discussed previously, legislation was enacted in Oklahoma and Arkansas that will restructure the electric utility industry in those states, assuming that all the conditions in the legislation are met. This legislation would deregulate OG&E's electric generation assets and the continued use of Statement of Financial Accounting Standards ("SFAS") No. 71, "Accounting for the Effects of Certain Types of

Regulation" with respect to the related regulatory assets may no longer be appropriate. 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 of up to $30 million, depending on the transition mechanisms developed by the legislature for the recovery of all or a portion of these net regulatory assets.

The enacted Oklahoma and Arkansas legislation does 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 assets is appropriate. However, if utility regulators in Oklahoma and Arkansas were to adopt regulatory methodologies in the future that are not based on cost-of-service, the continued use of SFAS No. 71 with respect to the regulatory assets 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.

As stated previously, the OCC in its 1997 Order, directed OG&E to commence competitively bid gas transportation service to its gas-fired plants no later than April 30, 2000. The order also set annual compensation for the transportation services provided by Enogex to OG&E at $41.3 million annually until March 1, 2000, at which time the rate would drop to $28.5 million (reflecting the completion of the recovery from ratepayers of the amortization premium paid by OG&E when it acquired Enogex in 1986) and remain at that level until competitively-bid gas transportation begins. Final firms bids were submitted by Enogex and other pipelines on April 15, 1999. In July 1999, OG&E filed an application with the OCC requesting approval of a performance-based rate plan for its Oklahoma retail customers from April 2000 until the introduction of customer choice for electric power in July 2002. As part of this application, OG&E stated that Enogex had submitted the only viable bid ($33.4 million per year) for gas transportation to its six gas-fired power plants that were the subject of the competitive bid. As part of its application to the OCC, OG&E offered to discount Enogex's bid from $33.4 million annually to $25.2 million annually. OG&E has executed a new gas transportation contract with Enogex under which Enogex would continue serving the needs of OG&E's power plants at a price to be paid by OG&E of $33.4 million annually and, if OG&E's proposal had been approved by the OCC, OG&E would have recovered a portion of such amount ($25.2 million) from its ratepayers. The OCC Staff, the office of the Oklahoma Attorney General and a coalition of industrial customers filed testimony questioning various parts of OG&E's performance-based rate plan, including the result of the competitive bid process, and suggested, among other things, that the bidding process be repeated or that gas transportation service to five of OG&E's gas-fired plants be awarded to parties other than Enogex. The OCC Staff also filed testimony stating in substance that OG&E's electric rates as a whole were appropriate and did not warrant a rate review. OG&E negotiated with these parties in an effort to settle all issues (including the competitive bid process) associated with its application for a performance-based rate plan. When these negotiations failed, OG&E withdrew its application, which withdrawal was approved by the OCC in December 1999. Based on filed testimony, OG&E believes that Enogex properly won the competitive bid and, unless OG&E's decision to award its gas transportation service to Enogex is abrogated by order of the OCC (which order is upheld on appeal), that it intends to fulfill its obligations under its new gas transportation contract with Enogex at a price of $33.4 million annually. Whether OG&E will be able to recover the entire amount from its ratepayers has not been determined as explained below.

On January 12, 2000, the Staff filed three applications to address various aspects of OG&E's electric rates. Two of the applications were expected, while the third pertains to recoveries under OG&E's fuel adjustment clause. The first application relates to the completion of the recovery of the amortization premium paid by OG&E when it acquired Enogex in 1986 and the resulting removal of this $12.8 million from the amounts currently being paid annually by OG&E to Enogex and being recovered by OG&E from its ratepayers. OG&E has consented to this action. The second application relates to a review of the GEP Rider, which, as part of the OCC's 1997 Order, was scheduled for review in March 2000. OG&E collected approximately $20.8 million pursuant to the GEP Rider during 1999. A hearing on the GEP Rider is scheduled in May 2000 and OG&E intends to support the retention of the GEP Rider with only minor modifications. The final application relates to a review of 1999 fuel cost recoveries. OG&E assumes that this application also will be used to address the competitive bid process of its gas transportation service. The Company cannot predict the precise outcome of these proceedings at this time, but does not expect that they will have a material effect on its operations.

On February 13, 1998, the APSC staff filed a motion for a show cause order to review OG&E's electric rates in the State of Arkansas. The Staff recommended a $3.1 million annual rate reduction (based on a test year ended December 31, 1996). The Staff and OG&E reached a settlement for a $2.3 million annual rate reduction, which was approved by the APSC in August 1999.

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 senior risk management committee has been established to review these risks on a regular basis. The Company is exposed to market risk, including changes in interest rates and certain commodity prices.

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. The fair value of long-term debt is estimated based on quoted market prices and management's estimate of current rates available for similar issues. The following table itemizes the Company's long-term debt maturities and the weighted-average interest rates by maturity date.

(DOLLARS IN MILLIONS)	2000	2001	2002	2003	2004	Thereafter	Total	1999 Year-end Fair Value
Fixed rate debt								
Principal amount......	$169.0	$ 2.0	$115.0	$ 14.3	$ 57.8	$818.4	$1,176.5	$1,032.8
Weighted-average interest rate.......	6.42%	7.15%	7.34%	7.70%	7.20%	7.27%	7.18%	---
Variable-rate debt								
Principal amount......	---	---	---	---	---	$135.4	$ 135.4	$ 135.4
Weighted-average interest rate.......	---	---	---	---	---	3.42%	3.42%	---

COMMODITY PRICE EXPOSURE

The market risk inherent in the Company's market risk sensitive instruments and positions is the potential loss in value arising from adverse changes in the Company's commodity prices.

The prices of natural gas and electricity are subject to fluctuations resulting from changes in supply and demand. To partially reduce price risk caused by these market fluctuations, the Company may hedge (through the utilization of derivatives) a portion of the Company's supply and related purchase and sale contracts, as well as any anticipated transactions (purchases and sales). 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 price exposure to the market risk of the Company's natural gas and electricity commodity positions. The Company's daily net commodity position consists of natural gas inventories, purchased electric capacity, commodity purchase and sales contracts, and derivative financial and commodity instruments. The fair value of such position is a summation of the fair values calculated for each commodity by valuing each net position at quoted futures 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 fiscal 2000:

(DOLLARS IN THOUSANDS)	Wholesale	Non-Trading
Commodity market risk, net................	$ 779	$ 853

In June 1998, the Financial Accounting Standards Board ("FASB") issued Statement of Financial Accounting Standards ("SFAS") No. 133, "Accounting for Derivative Instruments and for Hedging Activities", with an effective date for periods beginning after June 15, 1999. In July 1999, the FASB issued SFAS No. 137, "Accounting for Derivative Instruments and Hedging Activities - Deferral of the Effective Date of FASB Statement No. 133". As a result of SFAS No. 137, adoption of SFAS No. 133 is now required for financial statements for periods beginning after June 15, 2000. SFAS No. 133 sweeps in a broad population of transactions and changes the previous accounting definition of a derivative instrument. Under SFAS No. 133, every derivative instrument is recorded on the balance sheet as either an asset or liability measured at its fair value. SFAS No. 133 requires that changes in the derivative's fair value be recognized currently in earnings unless specific hedge accounting criteria are met. The Company will prospectively adopt this new standard effective January 1, 2001, and management believes the adoption of this new standard will not have a material impact on its consolidated financial position or results of operation.

Besides the various existing contingencies herein described, and those described in Note 10 of Notes to Consolidated Financial Statements, the Company's ability to fund its future operational needs and to finance its construction program is dependent upon numerous other factors beyond its control, such as general economic conditions, abnormal weather, load growth, inflation, new environmental laws or regulations, and the cost and availability of external financing.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK.

See Management's Discussion and Analysis of Financial Condition and Results of Operations, Market Risk.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA.

CONSOLIDATED BALANCE SHEETS

December 31 (DOLLARS IN THOUSANDS)	1999	1998	1997
ASSETS			
CURRENT ASSETS:			
Cash and cash equivalents	$ 7,271	$ 378	$ 4,257
Accounts receivable - customers, less reserve of $5,270, $3,342 and $4,507, respectively	263,708	141,235	117,842
Accrued unbilled revenues	40,200	22,500	36,900
Accounts receivable - other	10,462	12,902	11,470
Fuel inventories, at LIFO cost	117,185	57,288	49,369
Materials and supplies, at average cost	39,194	29,734	28,430
Prepayments and other	16,911	31,551	4,489
Accumulated deferred tax assets	8,729	7,811	6,925
Total current assets	503,660	303,399	259,682
OTHER PROPERTY AND INVESTMENTS, at cost	31,012	31,682	37,898
PROPERTY, PLANT AND EQUIPMENT:			
In service	5,209,783	4,391,232	4,125,858
Construction work in progress	56,553	50,039	25,799
Total property, plant and equipment	5,266,336	4,441,271	4,151,657
Less accumulated depreciation	2,024,349	1,914,721	1,797,806
Net property, plant and equipment	3,241,987	2,526,550	2,353,851
DEFERRED CHARGES:			
Advance payments for gas	11,800	15,000	10,500
Income taxes recoverable through future rates	39,692	40,731	42,549
Other	93,183	66,567	61,385
Total deferred charges	144,675	122,298	114,434
TOTAL ASSETS	$3,921,334	$2,983,929	$2,765,865

THE ACCOMPANYING NOTES TO CONSOLIDATED FINANCIAL STATEMENTS ARE AN INTEGRAL PART HEREOF.

CONSOLIDATED BALANCE SHEETS (Continued)

December 31 (DOLLARS IN THOUSANDS)	1999	1998	1997
LIABILITIES AND STOCKHOLDERS' EQUITY			
CURRENT LIABILITIES:			
Short-term debt	$ 589,100	$ 119,100	$ 1,000
Accounts payable	161,183	96,936	77,733
Dividends payable	25,889	26,865	27,428
Customers' deposits	22,138	23,985	23,847
Accrued taxes	41,215	30,500	21,677
Accrued interest	28,191	21,081	20,041
Long-term debt due within one year	169,000	2,000	25,000
Other	40,145	35,366	38,518
Total current liabilities	1,076,861	355,833	235,244
LONG-TERM DEBT	1,140,532	935,583	841,924
DEFERRED CREDITS AND OTHER LIABILITIES:			
Accrued pension and benefit obligation	16,686	17,952	62,023
Accumulated deferred income taxes	566,137	531,940	503,952
Accumulated deferred investment tax credits	62,578	67,728	72,878
Other	39,161	31,511	15,618
Total deferred credits and other liabilities	684,562	649,131	654,471
STOCKHOLDERS' EQUITY:			
Common stockholders' equity	441,847	513,614	512,897
Preferred stockholders' equity	---	---	49,266
Retained earnings	577,532	529,768	472,063
Total stockholder's equity	1,019,379	1,043,382	1,034,226
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$3,921,334	$2,983,929	$2,765,865

THE ACCOMPANYING NOTES TO CONSOLIDATED FINANCIAL STATEMENTS ARE AN INTEGRAL PART HEREOF.

CONSOLIDATED STATEMENTS OF CAPITALIZATION

December 31 (DOLLARS IN THOUSANDS)	1999	1998	1997
COMMON STOCK AND RETAINED EARNINGS:			
Common stock, par value $0.01 per share; authorized 125,000,000 shares; and outstanding 77,863,370, 80,797,539, and 80,771,834 shares, respectively	$ 779	$ 808	$ 808
Premium on capital stock	411,068	512,806	512,089
Retained earnings	577,532	529,768	472,063
Total common stock and retained earnings	1,019,379	1,043,382	984,960
CUMULATIVE PREFERRED STOCK:			
Par value $20, authorized 675,000 shares - 4%; zero, zero, and 418,963 shares, respectively	---	---	8,379
Par value $100, authorized 1,865,000 shares-			
SERIES SHARES OUTSTANDING			
4.20% zero, zero, and 49,750 shares, respectively	---	---	4,975
4.24% zero, zero, and 74,990 shares, respectively	---	---	7,499
4.44% zero, zero, and 63,200 shares, respectively	---	---	6,320
4.80% zero, zero, and 70,925 shares, respectively	---	---	7,093
5.34% zero, zero, and 150,000 shares, respectively	---	---	15,000
Total cumulative preferred stock	---	---	49,266
LONG-TERM DEBT:			
SERIES DATE DUE			
6.375% January 1, 1998	---	---	25,000
7.125% January 1, 1999	---	---	12,500
6.250% Senior Notes Series B, October 15, 2000	110,000	110,000	110,000
7.125% January 1, 2002	---	---	40,000
8.625% November 1, 2007	---	---	35,000
6.500% Senior Notes Series D, July 15, 2017	125,000	125,000	125,000
7.300% Senior Notes Series A, October 15, 2025	110,000	110,000	110,000
6.650% Senior Notes Series C, July 15, 2027	125,000	125,000	125,000
6.500% Senior Notes Series E, April 15, 2028	100,000	100,000	---
Other bonds-			
Var. % Garfield Industrial Authority, January 1, 2025	47,000	47,000	47,000
Var. % Muskogee Industrial Authority, January 1, 2025	32,400	32,400	32,400
Var. % Muskogee Industrial Authority, June 1, 2027	56,000	56,000	56,000
Unamortized premium and discount, net	(2,354)	(2,488)	(976)
Enogex Inc. notes (Note 6)	233,486	234,671	150,000
Transok Holding LLC (Note 6)	173,000	---	---
Trust Originated Preferred Securities (Note 5)	200,000	---	---
Total long-term debt	1,309,532	937,583	866,924
Less long-term debt due within one year	169,000	2,000	25,000
Total long-term debt (excluding long-term debt due within one year)	1,140,532	935,583	841,924
Total Capitalization	$2,159,911	$1,978,965	$1,876,150

THE ACCOMPANYING NOTES TO CONSOLIDATED FINANCIAL STATEMENTS ARE AN INTEGRAL PART HEREOF.

CONSOLIDATED STATEMENTS OF INCOME

Year ended December 31 (DOLLARS IN THOUSANDS EXCEPT PER SHARE DATA)	1999	1998	1997
OPERATING REVENUES	$2,172,434	$1,617,737	$1,443,610
OPERATING EXPENSES:			
Fuel	309,327	315,194	277,806
Purchased power	249,203	240,542	222,464
Gas and Electricity purchased for resale	672,281	216,432	172,764
Other operation and maintenance	382,235	305,106	311,337
Depreciation and amortization	165,041	149,818	142,632
Taxes other than income	56,182	51,188	48,157
Total operating expenses	1,834,269	1,278,280	1,175,160
OPERATING INCOME	338,165	339,457	268,450
OTHER INCOME (EXPENSES):			
Interest charges	(100,279)	(70,699)	(66,495)
Other, net	3,317	5,758	7,161
Total other income (expenses)	(96,962)	(64,941)	(59,334)
EARNINGS BEFORE INCOME TAXES	241,203	274,516	209,116
PROVISION FOR INCOME TAXES	89,944	108,644	76,566
NET INCOME	151,259	165,872	132,550
PREFERRED DIVIDEND REQUIREMENTS	---	733	2,285
EARNINGS AVAILABLE FOR COMMON STOCK	$ 151,259	$ 165,139	$ 130,265
AVERAGE COMMON SHARES OUTSTANDING (thousands)	77,916	80,772	80,745
EARNINGS PER AVERAGE COMMON SHARE	1.94	2.04	1.61
AVERAGE COMMON SHARES OUTSTANDING ASSUMING DILUTION (thousands)	77,916	80,787	80,745
EARNINGS PER AVERAGE COMMON SHARE ASSUMING DILUTION	$ 1.94	$ 2.04	$ 1.61

THE ACCOMPANYING NOTES TO CONSOLIDATED FINANCIAL STATEMENTS ARE AN INTEGRAL PART HEREOF.

CONSOLIDATED STATEMENTS OF RETAINED EARNINGS

Year ended December 31 (DOLLARS IN THOUSANDS)	1999	1998	1997
BALANCE AT BEGINNING OF PERIOD	$ 529,768	$ 472,063	$ 449,198
ADD - net income	151,259	165,872	132,550
Total	681,027	637,935	581,748
DEDUCT:			
Cash dividends declared on preferred stock	---	733	2,285
Cash dividends declared on common stock	103,495	107,434	107,400
Total	103,495	108,167	109,685
BALANCE AT END OF PERIOD	$ 577,532	$ 529,768	$ 472,063

THE ACCOMPANYING NOTES TO CONSOLIDATED FINANCIAL STATEMENTS ARE AN INTEGRAL PART HEREOF.

CONSOLIDATED STATEMENTS OF CASH FLOWS

Year ended December 31 (DOLLARS IN THOUSANDS)	1999	1998	1997
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net Income	$ 151,259	$ 165,872	$ 132,550
Adjustments to Reconcile Net Income to Net Cash Provided from Operating Activities:			
Depreciation and amortization	165,041	149,818	142,632
Deferred income taxes and investment tax credits, net	31,093	23,922	17,105
Gain on sale of assets	---	---	(2,511)
Change in Certain Current Assets and Liabilities:			
Accounts receivable - customers	(69,875)	(23,393)	11,132
Accrued unbilled revenues	(17,700)	14,400	(2,000)
Fuel, materials and supplies inventories	(25,049)	(9,223)	9,753
Accumulated deferred tax assets	(918)	(886)	3,142
Other current assets	17,192	(25,627)	89
Accounts payable	9,668	19,203	(9,123)
Accrued taxes	10,715	8,823	(5,084)
Accrued interest	7,110	1,040	209
Other current liabilities	(48,451)	(3,577)	(73)
Other operating activities	(5,832)	(28,103)	(2,218)
Net cash provided from operating activities	224,253	292,269	295,603
CASH FLOWS FROM INVESTING ACTIVITIES:			
Capital expenditures	(181,163)	(235,231)	(163,571)
Acquisition of Transok	(531,767)	---	---
Other investing activities	2,832	(8,084)	4,900
Net cash used in investing activities	(710,098)	(243,315)	(158,671)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Retirement of long-term debt	(2,000)	(113,500)	(321,000)
Proceeds from long-term debt	---	100,000	336,000
Short-term debt, net	470,000	118,100	(40,400)
Retirement of common stock	(71,767)	---	---
Issuance of trust originated preferred securities	200,000	---	---
Redemption of preferred stock	---	(49,266)	(113)
Cash dividends declared on preferred stock	---	(733)	(2,285)
Cash dividends declared on common stock	(103,495)	(107,434)	(107,400)
Net cash provided from (used in) financing activities	492,738	(52,833)	(135,198)
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	6,893	(3,879)	1,734
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	378	4,257	2,523
CASH AND CASH EQUIVALENTS AT END OF PERIOD	$ 7,271	$ 378	$ 4,257
SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION			
Cash Paid During the Period for:			
Interest (net of amount capitalized)	$ 76,047	$ 59,792	$ 64,081
Income taxes	$ 52,428	$ 77,150	$ 64,705
NON-CASH INVESTING AND FINANCING ACTIVITIES			
Capital lease financing	$ ---	$ 9,818	$ ---
Debt assumed in acquisition	$ 173,000	$ 80,000	$ ---
Other investing and financing activities	$ 3,182	$ (3,000)	$ 5,185
Current liabilities assumed in acquisition of Transok	$ 98,917	$ ---	$ ---

THE ACCOMPANYING NOTES TO CONSOLIDATED FINANCIAL STATEMENTS ARE AN INTEGRAL PART HEREOF.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

ORGANIZATION

OGE Energy Corp. (the "Company") is the parent company of Oklahoma Gas and Electric Company ("OG&E"), Enogex Inc. ("Enogex") and OGE Energy Capital Trust I, a financing trust established in 1999. All significant intercompany transactions have been eliminated in consolidation.

The Company distributes 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.

On July 1, 1999, Enogex completed its acquisition of Tejas Transok Holding, L.L.C. and its subsidiaries ("Transok"), a gatherer, processor and transporter of natural gas in Oklahoma and Texas. Transok's principal assets include approximately 4,900 miles of natural gas pipelines in Oklahoma and Texas with a capacity of approximately 2.6 billion cubic feet per day and 18 billion cubic feet of underground natural gas storage. Transok also owns 9 gas-processing plants, which produced approximately 26,000 barrels per day of natural gas liquids in 1998. Enogex purchased Transok for $710.3 million, which included assumption of $173 million of long-term debt. The transaction was treated as a purchase for accounting purposes. The Company did not recognize any goodwill with this transaction.

The following unaudited pro forma financial information presents total operating revenues, net income and net income per share of the Company after giving effect to the Transok acquisition. The unaudited pro forma financial information for the twelve months ended December 31, 1999 gives effect to the acquisition as if it had occurred at January 1, 1999. The unaudited pro forma financial information for the twelve months ended December 31, 1998 gives effect to the acquisition as if it had occurred at January 1, 1998.

The following unaudited pro forma financial information has been prepared from, and should be read in conjunction with, the historical consolidated financial statements and related notes thereto of the Company. The following information is not necessarily indicative of the financial position or operating results that would have occurred had the transaction been consummated on the date, or at the beginning of the periods, for which the transaction is being given effect, nor is it necessarily indicative of future operating results or financial position.

Unaudited Pro Forma Financial Information

(DOLLARS IN THOUSANDS EXCEPT PER SHARE DATA)	PRO FORMA YEAR ENDED DECEMBER 31, 1999	PRO FORMA YEAR ENDED DECEMBER 31, 1998
Total operating revenues	$ 2,423,670	$ 2,088,497
Net income	146,991	132,728
Earnings per average common share	1.89	1.63
Earnings per average common share - assuming dilution	1.89	1.63

ACCOUNTING RECORDS

The accounting records of OG&E are maintained in accordance with the Uniform System of Accounts prescribed by the Federal Energy Regulatory Commission ("FERC") and adopted by the Oklahoma Corporation Commission ("OCC") and the Arkansas Public Service Commission ("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 expected recovery from customers in future rates. Likewise, certain credits that would otherwise reduce expense are deferred as regulatory liabilities based on 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, 1999, regulatory assets and regulatory liabilities are being amortized and reflected in rates charged to customers over periods up to 20 years.

The components of deferred charges - other, and regulatory assets and liabilities on the Consolidated Balance Sheets included the following, as of December 31:

DEFERRED CHARGES - OTHER

(DOLLARS IN THOUSANDS)	1999	1998	1997
Electric Utility Deferred Charges:			
Generating stations	$ 4,654	$ ---	$ ---
Unamortized debt expense	5,196	8,566	6,776
Unamortized loss on reacquired debt	27,281	29,072	28,660
Miscellaneous	4,116	2,217	403
Total electric utility deferred charges	41,247	39,855	35,839
Non-Electric Utility Deferred Charges:			
Enogex gas sales contracts	10,891	12,389	13,925
Enogex pipeline imbalance	11,238	---	---
Unamortized debt expense	10,008	---	---
Enogex minority interest asset	6,845	---	---
Miscellaneous	12,954	14,323	11,621
Total non-electric utility deferred charges	51,936	26,712	25,546
Total Deferred Charges	$ 93,183	$ 66,567	$ 61,385

REGULATORY ASSETS AND LIABILITIES

(DOLLARS IN THOUSANDS)	1999	1998	1997
Regulatory Assets:			
Income taxes recoverable from customers	$ 93,888	$ 104,160	$ 115,989
Unamortized loss on reacquired debt	27,281	29,072	28,660
Miscellaneous	4,116	2,217	403
Total Regulatory Assets	125,285	135,449	145,052
Regulatory Liabilities:			
Income taxes refundable to customers	(54,196)	(63,429)	(73,440)
Net Regulatory Assets	$ 71,089	$ 72,020	$ 71,612

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.

ACCOUNTING PRONOUNCEMENTS

In March 1998, the American Institute of Certified Public Accountants ("AICPA") issued Statement of Position ("SOP") 98-1, "Accounting for the Costs of Computer Software Developed or Obtained for Internal Use." Adoption of SOP 98-1 is required for fiscal years beginning after December 15, 1998. The Company adopted this new standard effective January 1, 1999. Adoption of this new standard did not have a material impact on consolidated financial position or results of operations.

In June 1998, the Financial Accounting Standards Board ("FASB") issued Statement of Financial Accounting Standards ("SFAS") No. 133, "Accounting for Derivative Instruments and for Hedging Activities", with an effective date for periods beginning after June 15, 1999. In July 1999, the FASB issued SFAS No. 137, "Accounting for Derivative Instruments and Hedging Activities - Deferral of the Effective Date of FASB Statement No. 133". As a result of SFAS No. 137, adoption of SFAS No. 133 is now required for financial statements for periods beginning after June 15, 2000. SFAS No. 133 sweeps in a broad population of transactions and changes the previous accounting definition of a derivative instrument. Under SFAS No. 133, every derivative instrument is recorded in the balance sheet as either an asset or liability measured at its fair value. SFAS No. 133 requires that changes in the derivative's fair value be recognized currently in earnings unless specific hedge accounting criteria are met. The Company will prospectively adopt this new standard effective January 1, 2001, and management believes the adoption of this new standard will not have a material impact on its consolidated financial position or results of operation.

In December 1998, the FASB Emerging Issues Task Force reached consensus on Issue No. 98-10, Accounting for Contracts Involved in Energy Trading and Risk Management Activities ("EITF Issue 98-10"). EITF Issue 98-10 is effective for fiscal years beginning after December 15, 1998. EITF Issue 98-10 requires energy trading contracts to be recorded at fair value on the balance sheet, with changes in fair value included in earnings. The Company adopted this new Issue effective January 1, 1999. Adoption of this Issue did not have a material impact on consolidated financial position or results of operations.

DERIVATIVES

In the normal course of business, Enogex and its subsidiaries utilize energy derivative contracts to hedge the price and basis risk associated with specifically identified purchase or sales contracts, natural gas inventories, production of gas reserves or operational needs. The Company accounts for changes in the market value of qualifying hedging instruments as deferred gains or losses until the production month of the hedged transaction, at which time the gain or loss on the hedging instrument and hedged transaction is recognized in the results of operations.

Additionally, Enogex through its energy trading subsidiary will utilize derivative contracts in its energy trading activities. Derivatives utilized in the energy trading activities are marked to market with the corresponding market gains or losses recognized in the results of operations as the market value changes.

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 financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

PROPERTY, PLANT AND EQUIPMENT

All property, plant and equipment is recorded at cost. Electric utility plant is recorded at its original cost. Newly constructed plant is added to plant balances at costs which include contracted services, direct labor, materials, overhead and allowance for funds used during construction. Replacement of major units of property are capitalized as plant. The replaced plant is removed from plant balances and the cost of such property together with the cost of removal 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.

DEPRECIATION

The provision for depreciation, which was approximately 3.2 percent of the average depreciable utility plant, for each of the years 1999, 1998 and 1997, 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 procedure.

Enogex's gas pipeline, gathering systems, compressors and gas processing plants are depreciated on a straight-line method over periods ranging from 17 to 83 years. Development and production properties are depreciated using the units-of-production method.

ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION

Allowance for funds used during construction ("AFUDC") is calculated according to FERC pronouncements for the imputed cost of equity and borrowed funds. AFUDC, a non-cash item, is reflected as a credit on the Consolidated Statements of Income and a charge to construction work in progress.

AFUDC rates, compounded semi-annually, were 5.36, 5.75 and 5.94 percent for the years 1999, 1998 and 1997, respectively.

FAIR VALUE OF FINANCIAL INSTRUMENTS

The carrying value of the financial instruments on the Consolidated Balance Sheets not otherwise discussed in these notes approximate fair value.

CASH AND CASH EQUIVALENTS

For purposes of these statements, the Company considers all highly liquid debt instruments purchased with a maturity of three months or less to be cash equivalents. These investments are carried at cost, which approximates market.

The Company's cash management program utilizes controlled disbursement banking arrangements. Outstanding checks in excess of cash balances totaled $11.7 million, $27.8 million and $18.5 million at December 31, 1999, 1998 and 1997, 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.

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 from a minimum of $1,500 to a maximum of $13,000 with a term of 6 months to 84 months. The finance rate is based upon short-term loan rates and is reviewed and updated periodically. The interest rates were 8.99, 8.25 and 8.25 percent at December 31, 1999, 1998 and 1997, respectively.

The current portion of these loans totaled $0.6 million, $1.0 million and $4.9 million at December 31, 1999, 1998 and 1997, respectively, and are classified as accounts receivable - customers in the accompanying Consolidated Balance Sheets. The noncurrent portion of these loans totaled $2.3 million, $4.0 million and $19.1 million at December 31, 1999, 1998 and 1997, respectively, and are classified as other property and investments in the accompanying Consolidated Balance Sheets. OG&E sold approximately $12.7 million and $25.0 million of its heat pump loans in 1999 and 1998 respectively.

REVENUE RECOGNITION

OG&E customers are billed monthly on a cycle basis. OG&E accrues estimated revenues for services provided but not yet billed, as the cost of providing service is recognized as incurred. Enogex accrues revenues as the products and services are delivered.

AUTOMATIC FUEL ADJUSTMENT CLAUSES

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

FUEL INVENTORIES

Fuel inventories for the generation of electricity consists 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 lower than the stated LIFO cost by approximately $0.9 million for 1999, $4.4 million for 1998, and $1.1 million for 1997, based on the average cost of fuel purchased late in the respective years. Natural gas products inventories are held for sale and accounted for based on the weighted average cost of production.

ACCRUED VACATION

The Company accrues vacation pay by establishing a liability for vacation earned during the current year, but is not payable until the following year. The accrued vacation totaled $14.4 million, $13.4 million and $13.2 million at December 31, 1999, 1998 and 1997, respectively, and is classified as other current liabilities in the accompanying Consolidated Balance Sheets.

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 AND STOCK SPLIT

Certain amounts have been reclassified on the consolidated financial statements to conform with the 1999 presentation. Effective June 15, 1998, the outstanding shares of the Company's common stock were split on a two-for-one basis. The new shares were issued to shareowners of record on June 1, 1998. Prior period shares, dividends and earnings per share of common stock have been restated to reflect the stock split.

2. INCOME TAXES

The items comprising tax expense are as follows:

Year ended December 31 (DOLLARS IN THOUSANDS)	1999	1998	1997
Provision For Current Income Taxes:			
Federal	$ 50,090	$ 72,084	$ 47,676
State	8,617	12,638	9,671
Total Provision For Current Income Taxes	58,707	84,722	57,347
Provisions (Benefit) For Deferred Income Taxes, net:			
Federal			
Depreciation	29,392	1,490	11,344
Repair allowance	1,978	1,200	794
Removal costs	3,461	(220)	774
Salvage	(3,131)	---	---
Casualty losses	5,167	---	---
Software implementation costs	---	---	4,840
Company restructuring	100	22	(494)
Pension expense	(2,626)	14,806	---
Bond redemption-unamortized costs	249	8,458	---
Other	(207)	20	2,093
State	1,858	3,296	2,904
Total Provision (Benefit) For Deferred Income Taxes, net	36,241	29,072	22,255
Deferred Investment Tax Credits, net	(5,150)	(5,150)	(5,150)
Income Taxes Relating to Other Income and Deductions	146	---	2,114
Total Income Tax Expense	$ 89,944	$ 108,644	$ 76,566
Pretax Income	$ 241,203	$ 274,516	$ 209,116

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

Year ended December 31	1999	1998	1997
Statutory federal tax rate	35.0%	35.0%	35.0%
State income taxes, net of federal income tax benefit	2.8	3.8	3.9
Tax credits, net	(3.4)	(3.0)	(4.0)
Other, net	2.9	3.8	1.7
Effective income tax rate as reported	37.3%	39.6%	36.6%

The Company files consolidated income tax returns. Income taxes are allocated to each company 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 ("temporary differences") 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 Income Taxes at December 31, 1999, 1998 and 1997 are as follows:

(DOLLARS IN THOUSANDS)	1999	1998	1997
Current Deferred Tax Assets:			
Accrued vacation	$ 5,497	$ 5,088	$ 4,221
Uncollectible accounts	1,776	1,242	1,898
Capitalization of indirect costs	249	172	106
RAR interest	774	774	---
Provision for Worker's Compensation claims	348	462	595
Other	85	73	105
Accumulated deferred tax assets	$ 8,729	$ 7,811	$ 6,925
Deferred Tax Liabilities:			
Accelerated depreciation and other property-related differences	$ 532,814	$ 491,943	$ 489,739
Allowance for funds used during construction	37,152	38,575	43,327
Income taxes recoverable through future rates	36,335	40,310	44,888
Bond redemption-unamortized costs	9,640	9,353	---
Total	615,941	580,181	577,954
Deferred Tax Assets:			
Deferred investment tax credits	(20,130)	(21,875)	(23,623)
Income taxes refundable through future rates	(20,974)	(24,547)	(28,421)
Postemployment medical and life insurance benefits	(1,795)	(3,100)	(4,174)
Company pension plan	(5,206)	(682)	(16,242)
Other	(1,699)	1,963	(1,542)
Total	(49,804)	(48,241)	(74,002)
Accumulated Deferred Income Tax Liabilities	$ 566,137	$ 531,940	$ 503,952

3. COMMON STOCK AND RETAINED EARNINGS

In May 1998, the Company's Board of Directors approved a two-for-one stock split of its common stock, par value $0.01 per share (the "Common Stock"), by declaring a 100 percent stock dividend payable June 15, 1998. Accordingly, each shareowner of record of the Common Stock received one additional share of Common Stock for each share of Common Stock held on June 1, 1998.

On January 15, 1999, the Company repurchased 3 million shares of its Common Stock under an Advanced Share Repurchase agreement with CIBC Oppenheimer Corp. The purchase price was $80.4 million or $26.8125 per share, the closing price on January 15, 1999. Under the terms of this Advanced Share Repurchase Agreement, the Company agreed to bear the risk of increases and the benefit of decreases on the price on the Common Stock until CIBC Oppenheimer Corp. replaced, through open market purchases or privately negotiated transactions, the shares sold to the Company. Also, there were 65,831, 25,705 and 28,896 shares of new stock issued pursuant to the Stock Incentive Plan during 1999, 1998 and 1997, respectively. The $71.7 million decrease in 1999 in premium on capital stock as presented on the Consolidated Statements of Capitalization, represents the repurchase of common stock which was only partially offset by the issuance of common stock pursuant to the Stock Incentive Plan. The $0.7 million increase in 1998 in premium on capital stock represents the issuance of common stock pursuant to the Stock Incentive Plan.

There were 8,509,564 shares of unissued common stock reserved for the various employee and Company stock plans at December 31, 1999. With the exception of the Stock Incentive Plan, the common stock requirements, pursuant to those plans, are currently being satisfied with stock purchased on the open market.

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 market value. The rights are scheduled to expire on December 11, 2000.

4. STOCK INCENTIVE PLAN

On January 21, 1998, the Company adopted a Stock Incentive 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 has authorized the issuance of up to 4,000,000 shares under the plan.

RESTRICTED STOCK

The Company had a Restricted Stock Plan whereby certain employees periodically received shares of the Company's common stock at the discretion of the Board of Directors. The Stock Incentive Plan replaced the Restricted Stock Plan. The Company distributed 65,831, 25,705 and 28,896 shares of common stock during 1999, 1998 and 1997, respectively. The Company also reacquired 13,195 and 14,552 shares in 1998 and 1997, respectively. The shares reacquired in 1997 were recorded as treasury stock. The restricted stock distributed in 1999 and 1998 vests at the end of three years. The restricted stock distributed in 1997 vests over four years at (20 percent in each of the first three years and 40 percent in the final year).

Changes in common stock were:

(THOUSANDS)	1999	1998	1997
Shares outstanding January 1	80,798	80,772	80,758
Repurchased shares	(3,000)	---	---
Issued/reacquired under the Restricted Stock Plan, net	65	26	14
Shares outstanding December 31	77,863	80,798	80,772

STOCK OPTIONS

In January 1999, the Company awarded approximately 443,600 stock options, with an exercise price of $28.75. In January 1998, the Company awarded approximately 443,800 stock options, with an exercise price of $25.9375. During 1998, 19,200 stock options were forfeited. These options vest in one-third annual installments beginning one year from the date of grant and have a contractual life of 10 years. At December 31, 1999, 868,200 stock options were outstanding. The remaining contractual life of these options is approximately nine years and eight years, respectively.

During 1996, the Company adopted SFAS 123 and pursuant to its provision elected to continue using the intrinsic value method of accounting for stock-based awards granted to employees in accordance with APB 25. Accordingly, the Company has not recognized compensation expense for its stock-based awards to employees. Using the Black-Scholes pricing model, the estimated fair value of each option granted was $2.07 in 1999.

The following table shows assumptions used to estimate the fair value of options granted in 1999:

Expected life of options	7 years
Risk-free interest rate	4.74%
Expected volatility	15.75%
Expected dividend yield	6.77%

The following table reflects pro forma earnings available for common stock had the Company elected to adopt the fair value approach to SFAS 123:

(DOLLARS IN THOUSANDS)		1999	1998	1997
Earnings available for common stock:	As Reported......	$151,259	$165,139	$130,265
	Pro Forma........	150,864	164,933	130,002

Reported and pro forma earnings per share amounts are equivalent for 1997 through 1999.

5. TRUST PREFERRED SECURITIES OF SUBSIDIARY

On October 21, 1999, the OGE Energy Capital Trust I, a wholly-owned financing trust of the Company, issued $200 million principal amount of 8.375 percent trust preferred securities that mature in 2039. The proceeds of this new debt were used to repay a portion of outstanding short-term borrowings under the revolving credit agreement implemented in connection with the Transok acquisition. Distributions paid by the financing trust on the preferred securities are financed through payments on debt securities issued by the Company and held by the financing trust, which are eliminated in the Company's consolidation. The preferred securities are redeemable at $25 per share beginning in 2004. Distributions and redemption payments are guaranteed by the Company. Distributions paid to preferred security holders are recorded as interest expense in the Consolidated Statements of Income.

6. LONG-TERM DEBT

On July 1, 1999, Enogex completed its acquisition of Transok for approximately $710.3 million, which included assumption of $173 million of long-term debt. To repay the remaining balance of the temporary short-term debt associated with the Transok acquisition, Enogex, on January 14, 2000, sold $400 million of unsecured 8.125 percent Senior Notes due January 15, 2010. Enogex entered into a series of interest rate swap agreements to manage interest costs associated with this $400 million issue. The effect of these swap agreements reduces the overall effective interest rate from 8.125 percent to 6.6875 percent during the first year. The balance of the proceeds from this new debt was used for general corporate purposes. The following table itemizes the new Enogex long-term debt assumed as part of the Transok acquisition:

December 31 (DOLLARS IN THOUSANDS)	1999
Series Due 2002 -- 7.32% - 8.13%..............................	$ 50,000
Series Due 2003 -- 6.60% - 8.28%..............................	12,300
Series Due 2004 -- 6.71% - 8.34%..............................	25,750
Series Due 2005 -- 6.81% -- 7.71%.............................	40,950
Series Due 2007 -- 8.28%......................................	3,000
Series Due 2008 -- 7.07%......................................	1,000
Series Due 2012 -- 8.35% - 8.90%..............................	10,000
Series Due 2017 -- 8.96%......................................	15,000
Series Due 2023 -- 7.75%......................................	15,000
Total..	$173,000

As of December 31, 1999, other Enogex long-term debt consisted of $77 million principal amount of 7.15 percent Senior Notes subject to semiannual principal payments of $1 million each and due June 1, 2018, $6.5 million principal amount of 7.00 percent Notes due July 1, 2020 and $150 million of medium-term notes at a composite rate of 6.97 percent. The following table itemizes the other Enogex long-term debt at December 31, 1999, 1998 and 1997:

December 31 (DOLLARS IN THOUSANDS)	1999	1998	1997
Series Due August 7, 2000 -- 6.76% - 6.77%....................	$ 27,000	$ 27,000	$ 27,000
Series Due August 31, 2000 -- 6.68%...........................	20,000	20,000	20,000
Series Due September 1, 2000 -- 6.70%.........................	10,000	10,000	10,000
Series Due August 7, 2002 -- 7.02% - 7.05%....................	63,000	63,000	63,000
Series Due July 23, 2004 -- 6.79%.............................	30,000	30,000	30,000
Series Due July 18, 2018 -- 7.15%.............................	77,000	79,000	---
Series Due July 1, 2020 -- 7.00%..............................	6,486	5,671	---
Total..	$233,486	$234,671	$150,000

Maturities of the Company's long-term debt during the next five years consist of $169 million in 2000; $2 million in 2001; $115 million in 2002; $14.3 million in 2003, and $55.8 million in 2004.

The Company has previously incurred costs related to debt refinancings. Unamortized debt expense and unamortized loss on reacquired debt, and unamortized premium and discount on long-term debt are being amortized over the life of the respective debt and are classified as deferred charges - other and long-term debt, respectively, in the accompanying Consolidated Balance Sheets.

7. SHORT-TERM DEBT

The Company borrows on a short-term basis, as necessary, by the issuance of commercial paper and by obtaining short-term bank loans. The maximum and average amounts of short-term borrowings during 1999 were $198.9 million and $154.91 million, respectively, at a weighted average interest rate of 5.36%. The weighted average interest rates for 1998 and 1997 were 5.75% and 5.94%, respectively. Short-term debt in the amount of $589.1 million was outstanding at December 31, 1999. The Company has the necessary regulatory approvals to incur up to $400 million in short-term borrowings at any one time. At December 31, 1999, the Company had in place a line of credit for up to $200 million, $100 million was to expire on January 15, 2000, and the remaining $100 million was to expire on January 15, 2004. In January 2000, the Company's line of credit was increased to $300 million ($200 million to expire on January 15, 2001, and $100 million to expire on January 15, 2004) and the Company terminated its $75 million credit agreement with CIBC Oppenheimer Corp. which was entered into for the share repurchase program.

8. PENSION AND POSTRETIREMENT BENEFIT PLANS

All eligible employees of the Company are covered by a non-contributory defined benefit pension plan. Under the plan, retirement benefits are primarily a function of both the years of service and the highest average monthly compensation for 60 consecutive months out of the last 120 months of service.

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. The Company made contributions of $3.8 million during 1999 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.

The plan's assets consist primarily of U.S. Government securities, listed common stock and corporate debt.

In addition to providing pension benefits, the Company provides certain medical and life insurance benefits for retired members ("postretirement benefits"). Employees retiring from the Company on or after attaining age 55 who have met certain length of service requirements are entitled to these benefits. The benefits are subject to deductibles, co-payment provisions and other limitations. OG&E charges to expense the SFAS No. 106 costs and includes an annual amount as a component of cost-of-service in future ratemaking proceedings.

A reconciliation of the funded status of the plans and the amounts included in the Company's Consolidated Balance Sheets:

Projected benefit obligations are as follows:

	Pension Plan			Postretirement Benefit Plans		
(DOLLARS IN THOUSANDS)	1999	1998	1997	1999	1998	1997
Beginning obligations...........	$(342,433)	$(320,842)	$(284,973)	$ (89,094)	$ (94,199)	$ (94,272)
Service cost....................	(8,241)	(8,272)	(6,529)	(2,695)	(2,030)	(2,144)
Interest cost...................	(21,363)	(21,766)	(20,803)	(6,003)	(5,748)	(6,365)
Participant contributions.......	---	---	---	(1,143)	(1,077)	(902)
Plan changes....................	---	(3,561)	---	(1,500)	---	---
Actuarial gains (losses)........	53,535	(8,568)	(32,667)	7,950	6,029	3,198
Benefits paid...................	17,695	20,345	24,130	9,057	7,931	6,286
Expenses........................	811	231	---	---	---	---
Ending obligations..............	$(299,996)	$(342,433)	$(320,842)	$ (83,428)	$ (89,094)	$ (94,199)

Fair value of plans' assets:

	Pension Plan			Postretirement Benefit Plans		
(DOLLARS IN THOUSANDS)	1999	1998	1997	1999	1998	1997
Beginning fair value............	$ 304,169	$ 242,254	$ 222,912	$ 52,264	$ 45,619	$ 39,066
Actual return on plans' assets..	22,517	30,865	33,489	3,245	5,133	8,047
Employer contributions..........	3,757	51,626	9,983	6,307	5,474	5,271
Participants' contributions.....	---	---	---	980	915	874
Benefits paid...................	(17,695)	(20,345)	(24,130)	(7,287)	(6,388)	(6,128)
Expenses........................	(811)	(231)	---	---	---	---
Other...........................	---	---	---	---	1,511	(1,511)
Ending fair value...............	$ 311,937	$ 304,169	$ 242,254	$ 55,509	$ 52,264	$ 45,619

Funded status of plans:

	Pension Plan			Postretirement Benefit Plans		
(DOLLARS IN THOUSANDS)	1999	1998	1997	1999	1998	1997
Funded status of the plans......	$ 11,941	$ (38,264)	$ (78,588)	$ (27,919)	$ (36,831)	$ (47,068)
Unrecognized net gain (loss)....	(47,326)	1,435	2,295	(24,337)	(18,713)	(13,886)
Unrecognized prior service benefit.......................	37,289	40,448	40,047	1,396	---	---
Unrecognized transition obligation....................	(2,527)	(3,790)	(5,053)	35,738	38,487	41,236
Net balance sheet asset (liability)...................	$ (623)	$ (171)	$ (41,299)	$ (15,122)	$ (17,057)	$ (19,718)

Net Periodic Benefit Cost:

(DOLLARS IN THOUSANDS)	Pension Plan 1999	Pension Plan 1998	Pension Plan 1997	Postretirement Benefit Plans 1999	Postretirement Benefit Plans 1998	Postretirement Benefit Plans 1997
Service cost....................	$ 8,241	$ 8,272	$ 6,529	$ 2,695	$ 2,030	$ 2,144
Interest cost...................	21,363	21,766	20,803	6,003	5,748	6,365
Return on plan assets...........	(27,374)	(21,443)	(19,142)	(3,963)	(4,309)	(3,445)
Amortization of transition obligation....................	(1,263)	(1,263)	(1,263)	2,749	2,749	2,749
Amortization of net gain (loss).	---	---	788	(1,244)	(2,105)	(858)
Net amount capitalized or deferred......................	(880)	---	---	(1,087)	(613)	(1,293)
Net amortization and deferral...	(29)	---	---	---	---	---
Amortization of unrecognized prior service cost............	3,159	3,159	2,939	104	---	---
Net periodic benefit costs......	$ 3,217	$ 10,491	$ 10,654	$ 5,257	$ 3,500	$ 5,662

Rate Assumptions:

	Pension Plan 1999	Pension Plan 1998	Pension Plan 1997	Postretirement Benefit Plans 1999	Postretirement Benefit Plans 1998	Postretirement Benefit Plans 1997
Discount rate....................	8.00%	6.75%	7.00%	8.00%	6.75%	7.00%
Rate of return on plans' assets...	9.00%	9.00%	9.00%	9.00%	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	7.00%	7.50%	8.25%
Ultimate trend rate............	N/A	N/A	N/A	4.50%	4.50%	4.50%
Ultimate trend year............	N/A	N/A	N/A	2007	2007	2007

N/A - not applicable

Assumed health care cost trend rates have a significant effect on the amounts reported for the postretirement medical benefit plans.

The effects of a one-percentage point increase on the aggregate of the service and interest components of the net periodic postretirement health care benefits would be approximately $1.0 million, $0.9 million and $1.0 million at December 31, 1999, 1998 and 1997, respectively. The effects of a one-percentage point decrease on the aggregate of the service and interest components of the net periodic postretirement health care benefits would be decreases of approximately $0.9 million, $0.7 million and $1.0 million at December 31, 1999, 1998 and 1997, respectively.

The effects of a one-percentage point increase on the aggregate of accumulated postretirement benefit obligation for health care benefits would be approximately $7.1 million, $8.2 million and $11.4 million at December 31, 1999, 1998 and 1997, respectively. The effects of a one-percentage point decrease on the aggregate of accumulated postretirement benefit obligation for health care benefits would be decreases of approximately $6.0 million, $6.9 million and $9.4 million at December 31, 1999, 1998 and 1997, respectively.

9. REPORT OF BUSINESS SEGMENTS

The Company's electric utility operations are conducted through OG&E, an operating public utility engaged in the generation, transmission, distribution and sale of electric energy. The non-utility operations are primarily conducted through Enogex. Enogex is engaged in transporting natural gas through its intra-state pipeline to various customers (including OG&E), gathering and processing natural gas, marketing electricity, natural gas and natural gas liquids and investing in the development for and production of natural gas and crude oil.

(DOLLARS IN THOUSANDS)	1999	1998	1997
Operating Information:			
Operating Revenues			
Electric utility	$1,286,844	$1,312,078	$1,191,691
Non-utility	1,086,105	506,471	293,608
Intersegment revenues (A)	(200,515)	(200,812)	(41,689)
Total	$2,172,434	$1,617,737	$1,443,610
Pre-tax Operating Income			
Electric utility	$ 269,564	$ 315,798	$ 246,038
Non-utility	68,601	23,659	22,412
Total	$ 338,165	$ 339,457	$ 268,450
Income Tax Expense			
Electric utility	$ 84,965	$ 105,574	$ 71,321
Non-utility	4,979	3,070	3,131
Total	$ 89,944	$ 108,644	$ 74,452
Interest Income			
Electric utility	$ 1,710	$ 2,314	$ 4,531
Non-utility	9,929	7,046	1,993
Intersegment (B)	(8,801)	(5,799)	(2,651)
Total	$ 2,838	$ 3,561	$ 3,873

Interest Expense			
Electric utility	$ 46,658	$ 49,941	$ 56,546
Non-utility	63,142	27,628	13,199
Intersegment (B)	(8,801)	(5,799)	(2,651)
Total	$ 100,999	$ 71,770	$ 67,094
Net Income			
Electric utility	$ 139,041	$ 160,338	$ 120,994
Non-utility	12,218	5,534	11,556
Total	$ 151,259	$ 165,872	$ 132,550
Investment Information:			
Identifiable Assets as of December 31			
Electric utility	$2,320,660	$2,320,097	$2,350,782
Non-utility	1,600,674	663,832	415,083
Total	$3,921,334	$2,983,929	$2,765,865
Other Information:			
Depreciation and amortization			
Electric utility	$ 119,059	$ 116,213	$ 114,760
Non-utility	45,982	33,605	27,872
Total	$ 165,041	$ 149,818	$ 142,632
Construction Expenditures			
Electric utility	$ 101,263	$ 96,678	$ 100,079
Non-utility	79,900	138,553	63,492
Total	$ 181,163	$ 235,231	$ 163,571

(A) Intersegment revenues are recorded at prices comparable to those of unaffiliated customers and are affected by regulatory considerations.
(B) Intersegment interest is calculated based upon short-term loan rates and is reviewed and updated periodically.

10. COMMITMENTS AND CONTINGENCIES

OG&E has entered into purchase commitments in connection with OG&E's construction program and the purchase of necessary fuel supplies of coal and natural gas for OG&E's generating units. The Company's construction expenditures for 2000 are estimated at $251 million.

OG&E acquires some of its natural gas for boiler fuel under four wellhead contracts, some of which contain provisions allowing the owners to require prepayments for gas if certain minimum quantities are not taken. At December 31, 1999, 1998 and 1997, outstanding prepayments for gas, including the amounts classified as current assets, under these contracts were approximately $14.9 million, $15.2 million and $10.7 million, respectively.

At December 31, 1999, OG&E held non-cancelable operating leases covering 1,495 coal hopper railcars. Rental payments are charged to fuel expense and recovered through OG&E's tariffs and automatic fuel adjustment clauses. The leases have purchase and renewal options. Future minimum lease payments due under the railcar leases, assuming the leases are renewed under the renewal option are as follows:

DOLLARS IN THOUSANDS

2000	$ 4,990	2003	$ 4,708
2001	4,896	2004	4,615
2002	4,802	2005 and beyond	44,562
Total Minimum Lease Payments			$68,573

Rental payments under operating leases were approximately $4.9 million in 1999, $5.3 million in 1998 and $5.4 million in 1997.

OG&E is required to maintain the railcars it has under lease to transport coal from Wyoming and has entered into agreements with Pregressive Rail Services and WATCO, both of which are non-affiliated companies, to furnish this maintenance.

OG&E had entered into an agreement with Central Oklahoma Oil and Gas Corp. ("COOG"), an unrelated third party, to develop a natural gas storage facility. Operation of the gas storage facility proved beneficial by allowing OG&E to lower fuel costs by base loading coal generation, a less costly fuel supply. During 1996, OG&E completed negotiations and contracted with COOG for gas storage service. Pursuant to the contract, COOG reimbursed OG&E for all outstanding cash advances and interest amounting to approximately $46.8 million. OG&E also entered into a bridge financing agreement as guarantor for COOG. In July 1997, COOG obtained permanent financing and issued a note in the amount of $49.5 million. The proceeds from the permanent financing were applied to repay the outstanding bridge financing. In connection with the permanent financing, the Company entered into a note purchase agreement, where it has agreed, upon the occurrence of a monetary default by COOG on its permanent financing, to purchase COOG's note at a price equal to the unpaid principal and interest under the COOG note. In July 1998, Enogex also agreed to lease underground gas storage from COOG. As part of this lease transaction, the Company agreed to make up to a $12 million secured loan to an affiliate of COOG. As part of this agreement, the Company has an $8 million loan outstanding repayable in 2003 and secured by the assets and stock of COOG. This loan is classified as other property and investments in the accompanying Consolidated Balance Sheets.

OG&E has entered into agreements with four qualifying cogeneration facilities having initial terms of 3 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 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 1999, 1998 and 1997, OG&E made total payments to cogenerators of approximately $229.3 million, $226.5 million and $212.2 million, of which $188.8 million, $185.5 million and $176.2 million, respectively, represented capacity payments. All payments for purchased power, including cogeneration, are included in the Consolidated Statements of Income as purchased power. The future minimum capacity payments under the contracts for the next five years are approximately: 2000 - $190 million, 2001 - $191 million, 2002 - $192 million, 2003 - $163 million and 2004 - $151 million.

Approximately $1.0 million of the Company's construction expenditures budgeted for 2000 are to comply with environmental laws and regulations.

The Company's management believes 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 $44.4 million during 2000, compared to approximately $43.5 million in 1999. 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.

Beginning in 2000, OG&E will be limited in the amount of sulfur dioxide it will be allowed to emit into the atmosphere. In order to meet this limit the Company has contracted for lower sulfur coal. OG&E believes this will allow it to meet this limit without additional capital expenditures. With respect to nitrogen oxides, OG&E continues to meet the current emission standard. However, pending regulations on regional haze, and Oklahoma's potential for not being able to meet the new ozone and particulate standards, could require further reductions in sulfur dioxide and nitrogen oxides. If this happens, significant capital expenditures and increased operating and maintenance costs would occur.

In 1997, the United States was a signatory to the Kyoto Protocol on global warming. If ratified by the U.S. Senate, this Protocol could have a tremendous impact on the Company's operations, by requiring the Company to significantly reduce the use of coal as a fuel source, since the Protocol would require a seven percent reduction in greenhouse gas emissions below the 1990 level.

OG&E is a party to two separate actions brought by the EPA concerning cleanup of disposal sites. OG&E was not the owner or operator of those sites, rather OG&E, along with many others, shipped materials to the owners or operators of the sites who disposed of the materials. Remediation and required monitoring at one of these sites has been completed and a consent decree from the EPA is being obtained for this site. OG&E's total waste disposed at the remaining site is minimal and on February 15, 1996, OG&E elected to participate in the de minimis settlement offered by EPA. One of the other potentially responsible parties is currently contesting OG&E's participation as a de minimis party. Regardless of the outcome of this issue, OG&E believes its ultimate liability for this site is minimal.

On October 22, 1998, Enogex entered into an option agreement to purchase two gas turbine generators for use in normal operations for approximately $27.5 million. This agreement was transferred to the Company in September 1999. These two generators produce approximately 50 megawatts of additional peak-load each. The total cost of this project is expected to be approximately $47 million. In August 1999, OG&E announced the reactivation of two of its generators that have been idle for several years. These two generators together produce approximately 115 megawatts of additional peak-load. The total cost of this reactivation project is expected to be approximately $9 million. By June 1, 2000, the Company plans to begin using these four generators, increasing its electric generating capacity by approximately 4 percent.

Trigen-Oklahoma City Energy Corp. ("Trigen") sued OG&E in the United States District Court, Western District of Oklahoma, alleging numerous causes of action, including monopolization of cooling services in violation of the Sherman Act. On December 21, 1998, the jury awarded Trigen in excess of $30 million in actual and punitive damages. On February 19, 1999, the trial court entered judgment in favor of Trigen as follows: (i) $6.8 million for various anti-trust violations, (ii) $4 million for tortious interference with an existing contract, (iii) $7 million for tortious interference with a prospective economic advantage and (iv) $10 million in punitive damages. The trial judge, in a companion order, acknowledged that portions of the judgment could be duplicative, that the antitrust amounts could be tripled and that parties should address these issues in their post-trial motions. On January 25, 2000, a trial judge rejected OG&E's post-trial motions to reverse the jury verdict or to grant OG&E a new trial. The judge did, however reduce the original $30 million judgment against OG&E to $20 million. OG&E expects to appeal the trial court's ruling. While the outcome of an appeal is uncertain, legal counsel and management believe it is not probable that Trigen will ultimately succeed in preserving the verdicts. Accordingly, the Company has not accrued any loss associated with the damages awarded. The Company believes that the ultimate resolution of this case will not have a material adverse effect on the Company's consolidated financial position or results of operations.

In the normal course of business, other lawsuits, claims, environmental actions and other governmental proceedings arise against the Company and its subsidiaries. Management, after consultation with legal counsel, does not anticipate that liabilities arising out of other currently pending or threatened lawsuits and claims will have a material adverse effect on the Company's consolidated financial position or results of operations.

11. RATE MATTERS AND REGULATION

The OCC in its 1997 Order, directed OG&E to commence competitively bid gas transportation service to its gas-fired plants no later than April 30, 2000. The order also set annual compensation for the transportation services provided by Enogex to OG&E at $41.3 million annually until March 1, 2000, at which time the rate would drop to $28.5 million (reflecting the completion of the recovery from ratepayers of the amortization premium paid by OG&E when it acquired Enogex in 1986) and remain at that level until competitively-bid gas transportation begins. Final firms bids were submitted by Enogex and other pipelines on April 15, 1999. In July 1999, OG&E filed an application with the OCC requesting approval of a performance-based rate plan for its Oklahoma retail customers from April 2000 until the introduction of customer choice for electric power in July 2002. As part of this application, OG&E stated that Enogex had submitted the only viable bid ($33.4 million per year) for gas transportation to its six gas-fired power plants that were the subject of the competitive bid. As part of its application to the OCC, OG&E offered to discount Enogex's bid from $33.4 million annually to $25.2 million annually. OG&E has executed a new gas transportation contract with Enogex under which Enogex would continue serving the needs of OG&E's power plants at a price to be paid by OG&E of $33.4 million annually and, if OG&E's proposal had been approved by the OCC, OG&E would have recovered a portion of such amount ($25.2 million) from its ratepayers. The OCC Staff, the Office of the Oklahoma Attorney General and a coalition of industrial customers filed testimony questioning various parts of OG&E's performance-based rate plan, including the result of the competitive bid process, and suggested, among other things, that the bidding process be repeated or that gas transportation service to five of OG&E's gas-fired plants be awarded to parties other than Enogex. The OCC Staff also filed testimony stating in substance that OG&E's electric rates as a whole were appropriate and did not warrant a rate review. OG&E negotiated with these parties in an effort to settle all issues (including the competitive bid process) associated with its application for a performance-based rate plan. When these negotiations failed, OG&E withdrew its application, which withdrawal was approved by the OCC in December 1999.

Based on filed testimony, OG&E believes that Enogex properly won the competitive bid and, unless OG&E's decision to award its gas transportation service to Enogex is abrogated by order of the OCC (which order is upheld on appeal), that it intends to fulfill its obligations under its new gas transportation contract with Enogex at a price of $33.4 million annually. Whether OG&E will be able to recover the entire amount from its ratepayers has not been determined as explained below.

On January 12, 2000, the Staff filed three applications to address various aspects of OG&E's electric rates. Two of the applications were expected, while the third pertains to recoveries under OG&E's fuel adjustment clause. The first application relates to the completion of the recovery of the amortization premium paid by OG&E when it acquired Enogex in 1986 and the resulting removal of this $12.8 million from the amounts currently being paid annually by OG&E to Enogex and being recovered by OG&E from its ratepayers. OG&E has consented to this action. The second application relates to a review of the GEP Rider, which, as part of the OCC's 1997 Order, was scheduled for review in March 2000. OG&E collected approximately $20.8 million pursuant to the GEP Rider during 1999. A hearing on the GEP Rider is scheduled in May 2000 and OG&E intends to support the retention of the GEP Rider with only minor modifications. The final application relates to a review of 1999 fuel cost recoveries. OG&E assumes that this application also will be used to address the competitive bid process of its gas transportation service. The Company cannot predict the precise outcome of these proceedings at this time, but does not expect that they will have a material effect on its operations.

On February 13, 1998, the APSC staff filed a motion for a show cause order to review OG&E's electric rates in the State of Arkansas. The Staff recommended a $3.1 million annual rate reduction (based on a test year ended December 31, 1996). The Staff and OG&E reached a settlement for a $2.3 million annual rate reduction and the APSC issued an order approving the settlement on August 6, 1999.

12. DISCLOSURES ABOUT FAIR VALUE OF FINANCIAL INSTRUMENTS

The fair value of Long-Term Debt and Preferred Securities is estimated based on quoted market prices and management's estimate of current rates available for similar issues. The fair value of the Enogex Notes is based on management's estimate of current rates available for similar issues with the same remaining maturities.

Indicated below are the carrying amounts and estimated fair values of the Company's financial instruments as of December 31:

	1999		1998		1997	
(DOLLARS IN THOUSANDS)	CARRYING AMOUNT	FAIR VALUE	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-Term Debt and Preferred Securities:						
Senior Notes........................	$457,646	$422,181	$567,512	$593,313	$581,524	$594,357
Industrial Authority Bonds..........	135,400	135,400	135,400	135,400	135,400	135,400
Enogex Inc. Notes...................	347,486	410,578	232,671	251,505	150,000	152,915
Trust Originated Preferred Securities........................	200,000	200,000	---	---	---	---
Preferred Stock: 4% - 5.34% Series - zero, zero and 827,828 shares, respectively..	---	---	---	---	49,266	49,997

13. SUBSEQUENT EVENTS

In January 2000, the Company increased its agreement for a line of credit from $200 million to $300 million, $200 million to expire on January 15, 2001, and $100 million to expire on January 15, 2004.

On January 12, 2000, the Staff filed three applications to address various aspects of OG&E's electric rates. Two of the applications were expected, while the third pertains to recoveries under OG&E's fuel adjustment clause. The first application relates to the completion of the recovery of the amortization premium paid by OG&E when it acquired Enogex in 1986 and the resulting removal of this $12.8 million from the amounts currently being paid annually by OG&E to Enogex and being recovered by OG&E from its ratepayers. OG&E has consented to this action. The second application relates to a review of the GEP Rider, which, as part of the OCC's 1997 order, was scheduled for review in March 2000. OG&E collected approximately $20.8 million pursuant to the GEP Rider during 1999. A hearing on the GEP Rider is scheduled in May 2000 and OG&E intends to support the retention of the GEP Rider with only minor modifications. The final application relates to a review of 1999 fuel cost recoveries. OG&E assumes that this application also will be used to address the competitive bid process of its gas transportation service. The Company cannot predict the precise outcome of these proceedings at this time, but does not expect that they will have a material effect on its operations.

On January 14, 2000, Enogex sold $400 million of 8.125 percent senior unsecured notes due January 15, 2010. Enogex entered into a series of interest rate swap agreements to manage interest costs associated with this $400 million issue. The effect of these swap agreements reduces the overall effective interest rate from 8.125 percent to 6.6875 percent during the first year. The proceeds from the sale of this new debt were used to repay the remaining balance of the temporary short-term debt associated with the Transok acquisition and for general corporate purposes.

Report of Independent Public Accountants

ARTHUR ANDERSEN LLP

TO THE SHAREOWNERS OF
OGE ENERGY CORP.:

We have audited the accompanying consolidated balance sheets and statements of capitalization of OGE Energy Corp. (an Oklahoma corporation) and its subsidiaries as of December 31, 1999, 1998 and 1997, and the related consolidated statements of income, retained earnings and cash flows for the years then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with 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 financial position of OGE Energy Corp. and its subsidiaries as of December 31, 1999, 1998 and 1997, and the results of their operations and their cash flows for the years then ended in conformity with accounting principles generally accepted in the United States.

/s/ Arthur Andersen LLP
Arthur Andersen LLP

Oklahoma City, Oklahoma,
January 20, 2000

Report of Management

TO OUR SHAREOWNERS:

The management of OGE Energy Corp. 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 certified public accountants 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, 1999, 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 certified public accountants to review matters relating to financial reporting, auditing and internal control. To ensure auditor independence, both the internal auditors and independent certified public accountants have full and free access to the Audit Committee.

The independent certified public accounting firm of Arthur Andersen 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/ James R. Hatfield	/s/ Donald R. Rowlett
James R. Hatfield, Sr. Vice President, Chief Financial Officer and Treasurer	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 results of operations for such periods:

Quarter ended (DOLLARS IN THOUSANDS EXCEPT PER SHARE DATA)		Dec 31	Sep 30	Jun 30	Mar 31
Operating revenues	1999	$ 575,978	$ 767,390	$ 450,861	$ 378,205
	1998	361,750	555,999	412,621	287,367
	1997	344,580	474,587	333,228	291,215
Operating income	1999	$ 50,570	$ 180,373	$ 73,147	$ 34,075
	1998	25,147	126,602	64,660	14,404
	1997	26,680	103,268	48,049	16,001
Net income (loss)	1999	$ 12,179	$ 90,204	$ 37,744	$ 11,132
	1998	10,230	108,117	47,865	(340)
	1997	12,205	89,520	31,085	(260)
Earnings (loss) available for common.stock	1999	$ 12,179	$ 90,204	$ 37,744	$ 11,132
	1998	10,230	108,117	47,865	(1,073)
	1997	11,634	88,949	30,513	(831)
Earnings (loss) per average common share	1999	$ 0.15	$ 1.16	$ 0.49	$ 0.14
	1998	0.13	1.33	0.59	(0.01)
	1997	0.14	1.10	0.38	(0.01)

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE.

Not Applicable.

PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT.

ITEM 11. EXECUTIVE COMPENSATION.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS.

Items 10, 11, 12 and 13 are omitted pursuant to General Instruction G of Form 10-K, since the Company filed copies of a definitive proxy statement with the Securities and Exchange Commission on or about March 28, 2000. Such proxy statement is incorporated herein by reference. In accordance with 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 14. 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:

o Consolidated Balance Sheets at December 31, 1999, 1998 and 1997

o Consolidated Statements of Income for the years ended December 31, 1999, 1998 and 1997

o Consolidated Statements of Retained Earnings for the years ended December 31, 1999, 1998 and 1997

o Consolidated Statements of Capitalization at December 31, 1999, 1998 and 1997

o Consolidated Statements of Cash Flows for the years ended December 31, 1999, 1998 and 1997

o Notes to Consolidated Financial Statements

o Report of Independent Public Accountants

o Report of Management

SUPPLEMENTARY DATA

o Interim Consolidated Financial Information

2. FINANCIAL STATEMENT SCHEDULE (INCLUDED IN PART IV)

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 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)
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 Report 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)

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 Report 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 Directors' Deferred Compensation Plan

10.07 Company's 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)

10.08 OG&E's Restoration of Retirement Income Plan, as amended. (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 OG&E's 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)

10.10 Company's Annual Incentive Compensation Plan. (Filed as Exhibit 10.12 to OGE Energy's Form 10-K for the year ended December 31, 1998 (File No. 1-12579) and incorporated by reference herein)

10.11 Company's Deferred Compensation Plan (Filed as Exhibit 4 to the Company's Form S-8 Registration Statement No. 333-92433 and incorporated by reference herein)

21.01 Subsidiaries of the Registrant.

23.01 Consent of Arthur Andersen LLP.

24.01 Power of Attorney.

27.01 Financial Data Schedule.

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 Directors' Deferred Compensation Plan

10.07 Company's 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)

10.08 OG&E's Restoration of Retirement Income Plan, as amended. (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 OG&E's 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)

10.10 Company's Annual Incentive Compensation Plan. (Filed as Exhibit 10.12 to OGE Energy's Form 10-K for the year ended December 31, 1998 (File No. 1-12579) and incorporated by reference herein)

10.11 Company's Deferred Compensation Plan (Filed as Exhibit 4 to the Company's Form S-8 Registration Statement No. 333-92423 and incorporated by reference herein)

(B) REPORTS ON FORM 8-K

Item 5. Other Events, dated May 20, 1999.
Item 5. Other Events, dated July 8, 1999.
Item 2. Acquisition of Assets, dated July 13, 1999.
Item 5. Other Events, dated July 16, 1999.
Item 7. Financial statements and Exhibits, dated July 13, 1999 (Form 8-K/A filed on September 13, 1999).
Item 7. Financial Statements and Exhibits, dated July 13, 1999 (Form 8-K/A-2 filed on September 14, 1999).
Item 5. Other Events, dated October 21, 1999.
Item 5. Other Events, dated December 8, 1999.

OGE ENERGY CORP.

SCHEDULE II - VALUATION AND QUALIFYING ACCOUNTS

COLUMN A DESCRIPTION	COLUMN B BALANCE BEGINNING OF YEAR	COLUMN C CHARGED TO COSTS AND EXPENSES	 CHARGED TO OTHER ACCOUNTS	COLUMN D DEDUCTIONS	COLUMN E BALANCE END OF YEAR
1999			(THOUSANDS)		
Reserve for Uncollectible Accounts	$ 3,342	$ 9,560	-	$ 7,632	$ 5,270
1998					
Reserve for Uncollectible Accounts	$ 4,507	$11,507	-	$12,672	$ 3,342
1997					
Reserve for Uncollectible Accounts	$ 4,626	$ 7,334	-	$ 7,453	$ 4,507

REPORT OF INDEPENDENT PUBLIC ACCOUNTANTS

To OGE Energy Corp.:

We have audited in accordance with auditing standards generally accepted in the United States, the consolidated financial statements of OGE Energy Corp. (an Oklahoma Corporation), and its subsidiaries included in this Form 10-K, and have issued our report thereon dated January 20, 2000. Our audits were made for the purpose of forming an opinion on those statements taken as a whole. The schedule listed on Page 83 Item 14 (a) 2. is the responsibility of the Company's management and is presented for purposes of complying with the Securities and Exchange Commission's rules and is not part of the basic financial statements. This schedule has been subjected to the auditing procedures applied in the audits of the basic financial statements and, in our opinion, fairly states in all material respects the financial data required to be set forth therein in relation to the basic financial statements taken as a whole.

/ s / Arthur Andersen LLP
Arthur Andersen LLP

Oklahoma City, Oklahoma,
January 20, 2000

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 24th day of March, 2000.

OGE ENERGY CORP.
(REGISTRANT)

/s/ Steven E. Moore
By 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 24, 2000
/ s / James R. Hatfield James R. Hatfield	Principal Financial Officer.	March 24, 2000
/ s / Donald R. Rowlett Donald R. Rowlett	Principal Accounting Officer.	March 24, 2000
Herbert H. Champlin	Director;	
Luke R. Corbett	Director;	
William E. Durrett	Director;	
Martha W. Griffin	Director;	
Hugh L. Hembree, III	Director;	
Robert Kelley	Director;	
Bill Swisher	Director; and	
Ronald H. White, M.D.	Director.	

/ s / Steven E. Moore
By Steven E. Moore (attorney-in-fact) March 24, 2000

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)
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 Report 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)
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 Report 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 Directors' Deferred Compensation Plan

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10.10 Company's Annual Incentive Compensation Plan. (Filed as Exhibit 10.12 to OGE Energy's Form 10-K for the Year ended December 31, 1998 (File No. 1-12579) and incorporated by reference herein)

10.11	Company's Deferred Compensation Plan (Filed as Exhibit 4 to the Company's Form S-8 Registration statement No. 333-92423 and incorporated by reference herein)
21.01	Subsidiaries of the Registrant.
23.01	Consent of Arthur Andersen LLP.
24.01	Power of Attorney.
27.01	Financial Data Schedule.
99.01	Cautionary Statement for Purposes of the "Safe Harbor" Provisions of the Private Securities Litigation Reform Act of 1995

EXHIBIT 10.06

OGE ENERGY CORP.
DIRECTORS' DEFERRED COMPENSATION PLAN

Effective January 1, 2000

OGE ENERGY CORP.
DIRECTORS' DEFERRED COMPENSATION PLAN

I. PURPOSE AND EFFECTIVE DATE

1.1. Purpose. The OGE Energy Corp. Directors' Deferred Compensation Plan has been established by OGE Energy Corp. to attract and retain non-employee members of its Board of Directors by providing a tax-deferred capital accumulation vehicle for such directors.

1.2. Effective Date. The Plan shall be effective January 1, 2000 and shall remain in effect until terminated in accordance with Article 9.

1.3. Continuation of Prior Plan. The Plan is intended to be an amendment, restatement and continuation of the Stock Equivalent and Deferred Compensation Plan For Directors of OGE Energy Corp. (the "Prior Plan").

II. DEFINITIONS

When used in the Plan and initially capitalized, the following words and phrases shall have the meanings indicated:

2.1. "Account" means the recordkeeping account established for each Participant in the Plan for purposes of accounting for the amount of Compensation deferred or Discretionary Awards, if any, awarded under Article 4, adjusted periodically to reflect assumed investment return on such deferrals and awards in accordance with Article 5.

2.2. "Administrator" means a committee consisting of the Chairman of the Board and the Company's President, Chief Financial Officer and Corporate Secretary or such other individual or committee appointed by the Board to administer the Plan in accordance with Article 8.

2.3. "Beneficiary" means the person or entity designated by the Participant to receive the Participant's Plan benefits in the event of the Participant's death. If the Participant does not designate a Beneficiary, or if the Participant's designated Beneficiary predeceases the Participant, the Participant's estate shall be the Participant's Beneficiary under the Plan.

2.4. "Board" means the Board of Directors of the Company.

2.5. "Change in Control" means the happening of any of the following events:

(a) An acquisition by any individual, entity or group (within the meaning of Section 13(d)(3) or 14(d)(2) of the Securities Exchange Act of 1934 ("Exchange Act")) (a "Person") of beneficial ownership (within the meaning of Rule 13d-3 promulgated under the Exchange Act) of 20% or more of either (1) the then outstanding shares of common stock of the Company (the "Outstanding Company Common Stock") or (2) the combined voting power of the then outstanding voting securities of the Company entitled to vote generally in the election of directors (the "Outstanding Company Voting Securities"); excluding however the following: (1) any acquisition directly from the Company, (2) any acquisition by the Company, (3) any acquisition by any employee benefit plan (or related trust) sponsored by or maintained by the Company or any corporation controlled by the Company or (4) any acquisition by any corporation pursuant to a transaction which complies with clauses (1), (2) and (3) of subsection (c) of this Section 2.5;

(b) a change in the composition of the Board such that the individuals who as of January 1, 2000, constitute the Board (the "Incumbent Board") cease for any reason to constitute at least a majority of the Board; provided, however, for purposes of this Section 2.5, that any individual who becomes a member of the Board subsequent to January 1, 2000, whose election or nomination for election by the Company's shareowners was approved by a vote of at least a majority of those individuals then comprising the Incumbent Board shall be considered as though such individual were a member of the Incumbent Board; but provided further, that any such individual whose initial assumption of office occurs as a result of either an actual or threatened election contest with respect to the election or removal of directors or other actual or threatened solicitation of proxies or consents by or on behalf of a Person other than the Board shall not be so considered as a member of the Incumbent Board; or

(c) consummation of a reorganization, merger, share exchange or consolidation or sale or other disposition of all or substantially all of the assets of the Company (a "Business Combination"), excluding, however, such a Business Combination pursuant to which (1) all or substantially all of the individuals and entities who are the beneficial owners, respectively, of the Outstanding Company Common Stock and Outstanding Company Voting Securities immediately prior to such Business Combination beneficially own, directly or indirectly, more than 60% of, respectively, the outstanding shares of common stock and the combined voting power of the then outstanding voting securities entitled to vote generally in the election of directors, as the case may be, of the corporation resulting from such Business Combination (including, without limitation, a corporation which as a result of such transaction owns the Company or all or substantially all of the Company's assets either directly or through one or more subsidiaries) in substantially the same proportions as their ownership, immediately prior to such Business Combination, of the Outstanding Company Common Stock and Outstanding Company Voting Securities, as the case may be, (2) no Person (other than the corporation resulting from such Business Combination or any employee benefit plan (or related trust) of the Company or such corporation resulting from such Business Combination) beneficially owns, directly or indirectly, 20% or more of, respectively, the outstanding shares of common stock of the corporation resulting from such Business Combination or the combined voting power of the outstanding voting securities of such corporation except to the extent that such ownership existed prior to the Business Combination and (3) at least a majority of the members of the board of directors of the corporation resulting from such Business Combination were members of the Incumbent Board at the time of the execution of the initial agreement, or the action of the Board providing for such Business Combination; or

(d) the approval by the shareholders of the Company of a complete liquidation or dissolution of the Company.

2.6. "Code" means the Internal Revenue Code of 1986, as amended.

2.7. "Company" means OGE Energy Corp. and any successor thereto.

2.8. "Compensation" means annual retainer and attendance fees payable to an Eligible Director for services as a member of the Board.

2.9. "Deferral Election" means the election made by an Eligible Director to defer Compensation in accordance with Article 4.

2.10. "Discretionary Award" means an award granted under the Plan to an Eligible Director in accordance with Section 4.5.

2.11. "Election Period" means the period specified by the Administrator during which a Deferral Election may be made with respect to Compensation payable for a Plan Year.

2.12. "Eligible Director" means a member of the Board who is not also an employee of the Company.

2.13. "Participant" means an Eligible Director who has elected to defer Compensation under the Plan or who has been credited with a Discretionary Award.

2.14. "Plan" means the OGE Energy Corp. Directors' Deferred Compensation Plan, as amended from time to time.

2.15. "Plan Year" means the calendar year.

2.16. "Valuation Date" means a date on which a Participant's Account is valued, which shall be the last day of each calendar month and such other dates as may be specified by the Administrator.

III. PARTICIPATION

An Eligible Director shall become a Participant in the Plan by filing a Deferral Election with the Administrator in accordance with Article 4. An Eligible Director who is not otherwise a Participant in the Plan shall become a Participant in the Plan on the date he or she is credited with a Discretionary Award.

IV. DEFERRAL OF COMPENSATION

4.1. <u>Deferral of Compensation</u>. An Eligible Director may elect to defer up to 100% of his or her Compensation for a Plan Year by filing a Deferral Election in accordance with Section 4.2.

4.2. Deferral Elections. A Participant's Deferral Election shall be in writing, and filed with the Administrator at such time and in such manner as the Administrator shall provide, subject to the following:

(a) Except as provided in subsection (d) below, a Deferral Election shall be made during the election period established by the Administrator which shall end no later than the day preceding the first day of the Plan Year in which such Compensation would otherwise be payable.

(b) Deferral Elections may be expressed as a percentage or fixed dollar amount of Compensation, within the limits provided under the Plan.

(c) The minimum annual deferral under the Plan shall be $2,500 and any Deferral Election which would provide a lesser deferral for a Plan Year shall be disregarded for such Plan Year.

(d) Notwithstanding the foregoing provisions of this Section 4.2, the Administrator, in its sole discretion, may provide that an individual who becomes an Eligible Director after the first day of a Plan Year may make a Deferral Election within 30 days of first becoming an Eligible Director, which Deferral Election shall relate to Compensation earned for periods after the date such election is made.

Once made, a Deferral Election shall remain in effect for subsequent Plan Years unless changed or revoked by the Participant in accordance with rules established by the Administrator. Any such modification or revocation shall be effective for the Plan Year following the Plan Year in which it is made; provided that such revocation shall become effective as soon as practicable in the event it is made because of the Participant's disability (as determined by the Administrator) or if the Administrator, in its sole discretion, determines that the Participant has suffered a severe financial hardship or a bona fide administrative mistake was made. If a Deferral Election is revoked in accordance with the preceding sentence, the Participant may not make a new Deferral Election until the election period established by the Administrator for making deferrals for the next Plan Year.

4.4. Crediting of Deferral Elections. The amount of Compensation that a Participant elects to defer under the Plan shall be credited by the Company to the Participant's Account as of the first day of the month next following the date the Compensation would have been payable absent the Deferral Election.

4.5. Discretionary Awards. The Administrator, in its sole discretion, may grant an Eligible Director a Discretionary Award under the Plan which shall be subject to the terms and conditions established by the Administrator, including those relating to how such credit shall be deemed invested and when such amount shall be credited to the Eligible Director's Account.

4.6. Account Under Prior Plan. As of the effective date of the Plan, each Participant's account balance under the Prior Plan, if any, shall be credited to the Participant's Account under this Plan.

V. PLAN ACCOUNTS

5.1. Valuation of Accounts. The Administrator shall establish an Account for each Participant who has filed a Deferral Election to defer Compensation, who has been awarded a Discretionary Award, or who has an account under the Prior Plan on the effective date of this Plan. Such Account shall be credited with a Participant's deferrals or Discretionary Awards as set forth in Sections 4.4 and 4.5, respectively, and with the Participant's Prior Plan account balance, if any. As of each Valuation Date, the Participant's Account shall be adjusted upward or downward to reflect (i) the investment return to be credited as of such Valuation Date pursuant to Section 5.2, and (ii) the amount of distributions, if any, to be debited as of that Valuation Date under Article 6 or Article 7.

5.2. Crediting of Investment Return. Subject to such rules and limitations as the Administrator may determine, each Participant shall designate from among the assumed investment alternatives established by the Administrator under Section 5.3, one or more assumed investments in which the amounts credited to his or her Account shall be deemed invested. As of each Valuation Date, a Participant's Account balance shall be adjusted upward or downward for increases and decreases in the fair market value of the investments in which it is deemed invested during the period since the immediately preceding Valuation Date. On or before the first day of each month, a Participant may make a new election with respect to the assumed investments in which his or her Account shall be deemed invested in the future. Any such election shall be made in the form and at the time specified by the Administrator; provided, however, that deferred amounts that would have been received in the form of Company common stock absent a deferral election shall be deemed to be invested in the assumed investment alternative based on the Company's common stock. If the Participant elected to have any portion of his or her account under the Prior Plan governed under Article 3 of the Prior Plan (relating to split dollar life insurance), the portion so elected shall continue to be subject to the provisions of such Article 3 and no assumed investment elections may be made with respect to such amount under this Section 5.2.

5.3. Assumed Investment Alternatives. The Administrator shall designate the assumed investment alternatives that will be available from time to time under the Plan for purposes of measuring a Participant's investment return under Section 5.2. Such assumed investment alternatives shall include an assumed investment in Company common stock. The value of deemed investments in Company common stock shall be determined based on the fair market value of a share of Company common stock as reported on the New York Stock Exchange composite tape at the close of business on the last business day of the month preceding the date on which the amount or value of such investment is being determined.

5.4. Investment Alternatives After Death. For periods after the Valuation Date coincident with or following a Participant's death, the Participant's Account balance shall be treated as if it were invested in a fixed interest rate account at prevailing short-term interest rates, as determined by the Administrator. Beneficiaries shall not be permitted to make elections with respect to assumed investment alternatives under the Plan.

VI. PAYMENT OF BENEFITS

6.1. Distribution at Specific Future Date. At the time a Participant initially elects to participate in the Plan, the Participant may elect one or more future Valuation Dates on which all or a portion of his or her Account as of such date shall be paid. Any such future date shall be a Valuation Date in a specific future year which is at least two Plan Years after the Plan Year for which the initial Deferral Election is made; provided, however, that only one distribution per Plan Year may be elected under this Section 6.1; provided, further that, if the Participant elects a distribution at one or more specific future dates and terminates service on the Board prior to any such date, distribution shall commence pursuant to Sections 6.2 or 7.1, as applicable. A distribution election under this Section 6.1 may be revoked or extended to a Valuation Date in a future Plan Year by filing a one-time revocation or extension election with the Administrator at least 12 months prior to the first day of the Plan Year in which such distribution was scheduled to take place.

6.2. Distribution Upon Termination of Board Service. Distribution of a Participant's Account shall be made or commence as of the Valuation Date coincident with or next following the Participant's termination of service on the Board. Distribution shall be made (i) in a lump sum, (ii) in substantially equal annual installments of up to 15 years, or (iii) in a combination of (i) and (ii), as elected by the Participant. A Participant may change the time and form of his or her distribution election under this Section 6.2 by filing a new election with the Administrator; provided, however, that any election that has not been on file with the Administrator at least 12 months prior to the first day of the Plan Year in which the Participant's termination of service on the Board occurs shall be disregarded. If the Participant does not have a valid election on file with the Administrator at the time Board membership ceases, the Participant's Account shall be paid in a single lump sum.

6.3. Unscheduled Withdrawal. A Participant may request a withdrawal of all or a portion of his or her Account by filing an election with the Administrator specifying the amount of the Account to be withdrawn. Payment of such amount, adjusted by the amount forfeited in subsection (a) below, shall be made as of the first Valuation Date administratively practicable after such request is received, and shall be subject to the following:

(a) An amount equal to 10% of the withdrawal requested shall be debited to the Participant's Account and permanently forfeited.

(b) Any Deferral Election in effect at the time of such withdrawal shall be void for periods after such withdrawal.

(c) The Participant shall not be eligible to file a new Deferral Election until the election period for the Plan Year commencing at least one year after such withdrawal.

6.4. Unforeseeable Emergency. Prior to the date otherwise scheduled for payment under the Plan, upon showing an unforeseeable emergency, a Participant may request that the Administrator accelerate payment of all or a portion of his or her Account in an amount not exceeding the amount necessary to meet the unforeseeable emergency. For purposes of the Plan, an unforeseeable emergency means an unanticipated emergency that is caused by an event beyond the control of the Participant and that would result in severe financial hardship to the Participant if early withdrawal were not permitted. The determination of an unforeseeable emergency shall be made by the Administrator in its sole discretion, based on such information as the Administrator shall deem to be necessary.

6.5. Time and Form of Elections. All distribution and withdrawal elections under this Article 6 shall be made at the time and in the form established by the Administrator and shall be subject to such other rules and limitations that the Administrator, in its sole discretion, may establish.

VII. DEATH BENEFITS

7.1. Death Prior to Commencement of Benefits. If a Participant dies prior to commencement of payment of his or her Account, the Participant's Beneficiary shall receive a survivor benefit in an amount equal to the sum of:

(a) the Participant's Account balance,

plus

(b) the Participant's total Compensation deferrals under the Plan for periods on or after January 1, 2000, multiplied by two.

Such survivor benefit shall be paid in a single lump sum as soon as practicable following the Participant's death.

7.2. Death After Commencement of Benefits. If a Participant dies after commencement of benefits but prior to the time his or her Account balance has been fully distributed, the Participant's Beneficiary shall receive the remaining portion of the Participant's Account at the regularly scheduled date of payment for any remaining installments payments of the Participant's Account.

7.3. Other Conditions. Notwithstanding the foregoing provisions of this Article 7, if the Participant's death occurs within two years of initial Plan participation, and such death occurs by reason of suicide (as reported on the Participant's death certificate or determined by the Administrator in good faith), the Participant's Beneficiary shall receive the Participant's Account balance as of the date of his or her death in full satisfaction of the Company's obligations under the Plan.

7.4. Administrator Discretion Regarding Form. Notwithstanding the foregoing provisions of this Article 7, a Beneficiary may request that the Administrator approve an alternate form of payment of survivor benefits under this Article 7 which request may be granted in the sole discretion of the Administrator.

VIII. ADMINISTRATION

8.1. Authority of Administrator. The Administrator shall have full power and authority to carry out the terms of the Plan. The Administrator's interpretation, construction and administration of the Plan, including any adjustment of the amount or recipient of the payments to be made, shall be binding and conclusive on all persons for all purposes. Neither the Company, including its officers, employees or directors, nor the Administrator or the Board or any member thereof, shall be liable to any person for any action taken or omitted in connection with the interpretation, construction and administration of the Plan.

8.2. Participant's Duty to Furnish Information. Each Participant shall furnish to the Administrator such information as it may from time to time request for the purpose of the proper administration of this Plan.

8.3. Claims Procedure. If a Participant or Beneficiary ("Claimant") is denied all or a portion of an expected benefit under this Plan for any reason, he or she may file a claim with the Administrator. The Administrator shall notify the Claimant within 90 days of allowance or denial of the claim, unless the Claimant receives written notice from the Administrator prior to the end of the 90-day period stating that special circumstances require an extension (of up to 90 additional days) of the time for decision. The notice of the decision shall be in writing, sent by mail to Claimant's last known address, and if a denial of the claim, shall contain the following information: (a) the specific reasons for the denial; (b) specific reference to pertinent provisions of the Plan on which the denial is based; and (c) if applicable, a description of any additional information or material necessary to perfect the claim, an explanation of why such information or material is necessary, and an explanation of the claims review procedure. A Claimant is entitled to request a review of any denial of his or her claim by the Board. The request for review must be submitted within 60 days of mailing of notice of the denial. Absent a request for review within the 60-day period, the claim shall be deemed to be conclusively denied. The Claimant or his or her representatives shall be entitled to review all pertinent documents, and to submit issues and comments in writing. The Board shall render a review decision in writing within 60 days after receipt of a request for a review, provided that, in special circumstances the Board may extend the time for decision by not more than 60 days upon written notice to the Claimant. The Claimant shall receive written notice of the Board's review decision, together with specific reasons for the decision and reference to the pertinent provisions of the Plan.

IX. AMENDMENT AND TERMINATION

The Board may amend or terminate the Plan at any time; provided, however, that no such amendment or termination shall have a material adverse effect on any Participant's rights under the Plan accrued as of the date of such amendment or termination. Upon termination of the Plan, the Board, in its discretion, may cause a lump-sum payment of all benefits for all Participants at substantially the same time.

X. MISCELLANEOUS

10.1. No Implied Rights; Rights on Termination of Service. Neither the establishment of the Plan nor any amendment thereof shall be construed as giving any Participant, Beneficiary or any other person, individually or as a member of a group, any legal or equitable right unless such right shall be specifically provided for in the Plan or conferred by specific action of the Board or the Administrator in accordance with the terms and provisions of the Plan. Except as expressly provided in this Plan, neither the Company nor any of its Affiliates shall be required or be liable to make any payment under the Plan.

10.2. Unfunded Plan. No funds shall be segregated or earmarked for any current or former Participant, Beneficiary or other person under the Plan. However, the Company may establish one or more trusts to assist in meeting its obligations under the Plan, the assets of which shall be subject to the claims of the Company's general creditors. No current or former Participant, Beneficiary or other person, individually or as a member of a group, shall have any right, title or interest in any account, fund, grantor trust, or any asset that may be acquired by the Company in respect of its obligations under the Plan (other than as a general creditor of the Company with an unsecured claim against its general assets). The Company may also choose to use life insurance to assist it in meeting its obligations under the Plan. As a condition of participation in the Plan, each Participant agrees to execute any documents that may be required in connection with obtaining such insurance and to cooperate with any life insurance underwriting requirements; provided, however, that a Participant shall not be required to undergo a medical examination in connection therewith.

10.3. Nontransferability. Prior to payment thereof, no benefit under the Plan shall be assignable or subject to any manner of alienation, sale, transfer, claims of creditors, pledge, attachment or encumbrances of any kind, except pursuant to a domestic relations order awarding benefits to an "alternate payee" (within the meaning of Code Section 414(p)(8)) that the Administrator determines satisfies the criteria set forth in paragraphs (1), (2) and (3) of Code Section 414(p) (a "DRO"). Notwithstanding any provision of the Plan to the contrary, the Plan benefits awarded to an alternate payee under a DRO shall be paid in a single lump sum to the alternate payee on the Valuation Date as soon as administratively practicable following the date the Administrator determines the order is a DRO, and such amounts, as adjusted for earnings, gains and losses, will be deducted from the Participant's Account as of such Valuation Date.

10.4. Successors and Assigns. The rights, privileges, benefits and obligations under the Plan are intended to be, and shall be treated as legal obligations of and binding upon the Company, its successors and assigns, including successors by merger, consolidation, reorganization or otherwise.

10.5. Applicable Law. This Plan is established under and will be construed according to the laws of the State of Oklahoma.

*   *   *

IN WITNESS WHEREOF, the undersigned has caused this Plan to be executed this ______ day of _________________, 2000.

OGE ENERGY CORP.

By_____________________________

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
Transok	Delaware	100.0

The above listed subsidiaries have been consolidated in the Registrant's financial statements.

EXHIBIT 23.01

CONSENT OF INDEPENDENT PUBLIC ACCOUNTANTS

As independent public accountants, we hereby consent to the incorporation of our reports dated January 20, 2000 included in the OGE Energy Corp. Form 10-K for the year ended December 31, 1999, into the previously filed Post-Effective Amendment No. 1-B to Registration Statement No. 33-61699, Post-Effective Amendment No. 2-B to Registration Statement No. 33-61699, Form S-8 Registration Statement No. 333-71327 and Form S-8 Registration Statement No. 333-92423.

/ s / Arthur Andersen LLP
Arthur Andersen LLP

Oklahoma City, Oklahoma,
March 24, 2000

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, 1999; 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 19th day of January 2000.

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
Hugh L. Hembree, III, Director	/ s / Hugh L. Hembree, III
Robert Kelley, Director	/ s / Robert Kelley
Bill Swisher, Director	/ s / Bill Swisher
Ronald H. White, M.D., Director	/ s / Ronald H. White, M.D.
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 OKLAHOMA)

On the date indicated above, before me, Debbie 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 19th day of January, 2000.

/s/ Debbie Peters
Debbie Peters
Notary Public in and for the County
of Oklahoma, State of Oklahoma

My Commission
Expires: May 3, 2003

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This schedule contains summary financial information extracted from the OGE Energy Corp. Consolidated Statements of Income, Balance Sheets, and Statements of Cash Flow as reported on Form 10-K as of December 31, 1999 and is qualified in its entirety by reference to such Form 10-K.

YEAR
DEC-31-1999
DEC-31-1999
PER-BOOK
3,241,987
31,012
503,660
144,675
0
3,921,334
779
441,068
577,532
1,019,379
0
0
1,140,532
0
0
589,100
169,000
0
9,831
2,475
991,017
3,921,334
2,172,434
89,944
1,834,269
1,924,213
248,221
3,317
251,538
100,279
151,259
0
151,259
103,495
60,727
224,253
1.94
1.94

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 electricity and natural gas on both a global and regional basis;

- Economic conditions including 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, collective bargaining agreements with union employees, or work stoppages;

- 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;

- 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 10 of the Notes to the Consolidated Financial Statements of the Company's Annual Report on Form 10-K for the year ended December 31, 1999, 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.