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

OR

[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended December 31, 2000 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 28, 2001, Common Shares outstanding were 77,921,997. Based upon the closing price on the New York Stock Exchange on February 28, 2001, the aggregate market value of the voting stock held by nonaffiliates of the Company was: Common Stock $1,809,348,770.

The proxy statement for the 2001 annual meeting of shareowners is incorporated by reference into Part III of this Report.

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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 serves as the parent holding company to its two primary subsidiaries, Oklahoma Gas and Electric Company ("OG&E") and Enogex Inc. ("Enogex").

Despite the continuing growth at Enogex, 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 generating stations with a total capability of 5,781 megawatts.

Enogex owns and operates approximately 9,700 miles of natural gas transmission and gathering pipelines, has interests in 13 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 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 electric suppliers by July 1, 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 law initially targeted customer choice of electricity providers by January 1, 2002, but in February 2001, the law was amended to delay customer choice until October 1, 2003. It now appears that customer choice of electricity suppliers may also be delayed in Oklahoma beyond 2002. 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 2000, 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 91 percent of total electric operating revenues for the year ended December 31, 2000, 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 5,754 megawatts, and occurred on August 29, 2000. OG&E's load responsibility peak demand was approximately 5,570 megawatts on August 29, 2000, resulting in a capacity margin of approximately 17.7 percent. As reflected in the table below and in the operating statistics on page 3, total kilowatt-hour sales increased 5.9 percent in 2000 as compared to a decrease of 2.2 percent in 1999 and a 4.2 percent increase in 1998. Kilowatt-hour sales to OG&E's customers ("system sales") increased 6.5 percent due to more favorable weather in the last six months of 2000. Sales to other utilities and power marketers ("off-system sales") decreased 31.5 percent, 48.6 percent and 39.5 percent in 2000, 1999 and 1998, respectively. In 1999, total kilowatt-hour sales decreased due to a decrease in system sales and off-system sales, both of which were higher in 1998 because of the record heat experienced in the summer of 1998.

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

SALES (Millions of Kwh)

	2000	Inc/ (Dec)	1999	Inc/ (Dec)	1998	Inc/ (Dec)
System Sales	25,002	6.5%	23,468	(0.7%)	23,642	6.6%
Off-System Sales	256	(31.5%)	374	(48.6%)	728	(39.5%)
Total Sales	25,258	5.9%	23,842	(2.2%)	24,370	4.2%

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		
	2000	1999	1998
ELECTRIC ENERGY:			
(Millions of Kwh)			
Generation (exclusive of station use)	23,327	21,788	22,565
Purchased	3,634	3,795	3,984
Total generated and purchased	26,961	25,583	26,549
Company use, free service and losses	(1,703)	(1,741)	(2,179)
Electric energy sold	25,258	23,842	24,370
ELECTRIC ENERGY SOLD:			
(Millions of Kwh)			
Residential	7,974	7,509	7,959
Commercial and industrial	12,729	11,985	11,912
Public street and highway lighting	70	69	68
Other sales to public authorities	2,458	2,354	2,352
System sales for resale	1,771	1,551	1,351
Total system sales	25,002	23,468	23,642
Off-system sales	256	374	728
Total sales	25,258	23,842	24,370
ELECTRIC OPERATING REVENUES:			
(Thousands)			
Electric Revenues:			
Residential	$ 575,656	$ 515,299	$ 537,486
Commercial and industrial	643,576	557,884	554,589
Public street and highway lighting	10,301	9,736	9,618
Other sales to public authorities	124,217	108,159	110,522
System sales for resale	58,117	42,918	38,763
Total system sales	1,411,867	1,233,996	1,250,978
Off-system sales	12,948	27,894	37,435
Total Electric Revenues	1,424,815	1,261,890	1,288,413
Miscellaneous	28,770	24,954	23,665
Total Operating Revenues	$ 1,453,585	$ 1,286,844	$ 1,312,078
NUMBER OF ELECTRIC CUSTOMERS:			
(At end of period)			
Residential	603,826	599,702	598,378
Commercial and industrial	86,659	86,837	86,251
Public street and highway lighting	364	249	249
Other sales to public authorities	11,501	11,151	11,183
Sales for resale	52	56	39
Total	702,402	697,995	696,100
RESIDENTIAL ELECTRIC SERVICE:			
Average annual use (Kwh)	13,264	12,546	13,342
Average annual revenue	$ 957.54	$ 860.98	$ 900.94
Average price per Kwh (cents)	7.22	6.86	6.75

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, 2000, approximately 88 percent of OG&E's electric revenue was subject to the jurisdiction of the OCC, seven percent to the APSC, and five percent to the FERC.

Recent Regulatory Matters

On January 12, 2000, the OCC Staff (the "Staff") filed three applications to address various aspects of OG&E's electric rates. The first application related to the completion on March 1, 2000, of the recovery of the amortization premium paid by OG&E when it acquired Enogex in 1986 and the resulting removal, pursuant to the Acquisition Premium Credit Rider ("APC Rider"), of $12.8 million ($10.7 million in the Oklahoma Jurisdiction) from the amount being recovered by OG&E from its customers through currently authorized electric rates. OG&E consented to this action and in March 2000, the OCC approved the APC Rider for $10.7 million annually.

The second application related to a review of the Generation Efficiency Performance Rider ("GEP Rider"), which, as part of the OCC's order issued in 1997 in connection with OG&E's last general rate review (the "1997 Order"), was scheduled for review in March 2000. OG&E collected approximately $9.9 million pursuant to the GEP Rider during 2000. The GEP Rider initially was designed so that when OG&E's average annual cost of fuel per kwh was 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 was allowed to collect, through the GEP Rider, one-third of the amount by which OG&E's average annual cost of fuel was below 96.261 percent of the average of the other specified utilities. If OG&E's fuel cost exceeded 103.739 percent of the stated average, OG&E was not allowed to recover one-third of the fuel costs above that average from Oklahoma customers. In April 2000 testimony, the Staff stated that they continued to support incentive programs that reward superior performance, but in their view the existing GEP Rider was not functioning as they had originally envisioned it.

In June 2000, the OCC approved the collection of $6.6 million through the GEP Rider for the time period July 1, 2000 through June 30, 2001 and approved the following four modifications to the GEP Rider: (i) changing OG&E's peer group to include utilities with a higher coal-to-gas generation mix; (ii) reducing the amount of fuel costs that can be recovered if OG&E's costs exceed the new peer group by changing the percentage above which OG&E will not be allowed to recover one-third of the fuel costs from Oklahoma customers from 103.739 percent to 101.0 percent; (iii) reducing OG&E's share of cost savings as compared to its new peer group from 33 percent to 30 percent; and (iv) limiting to $10.0 million the amount of any awards paid to OG&E or penalties charged to OG&E. The GEP Rider is to be revised effective July 1 of each year to reflect changes in the relative annual cost of fuel reported for the preceding calendar year.

The final application, relating to fuel cost recoveries, was used by the Staff to address the competitive bid process of OG&E's gas transportation needs. In the 1997 Order, the OCC approved a stipulation wherein OG&E agreed to initiate a competitive bidding process for gas transportation service to its gas-fired plants, with the competitive services commencing no later than April 30, 2000. The 1997 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 removal of the APC Rider, upon the completion of the recovery from customers of the amortization premium paid by OG&E when it acquired Enogex in 1986) and remain at that level until competitively-bid gas transportation began. 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 OG&E's 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 executed a gas transportation contract with Enogex under which Enogex continues to serve 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 customers. OG&E negotiated with the Staff, the Office of the Oklahoma Attorney General and a coalition of industrial customers 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.

In July 2000, OG&E entered into a stipulation (the "Stipulation") with the Staff, the Office of the Attorney General and a coalition of industrial customers regarding the competitive bid process of OG&E's gas transportation service. The Stipulation (which, with one exception, was signed by all parties to the proceeding) would permit OG&E to recover $25.2 million annually for gas transportation services to be provided by Enogex pursuant to the competitive bid process. The Stipulation was presented for approval to an Administrative Law Judge ("ALJ") in September 2000, and the ALJ recommended its approval. However, at a hearing on September 28, 2000, the OCC chose to delay the decision concerning the Stipulation and two of the three commissioners expressed concern over the competitive bid process. OG&E cannot predict what further action the OCC may take. OG&E believes that the competitive bid process was appropriate and is currently collecting $28.5 million on an annual basis through its base rates and APC Rider for gas transportation services from Enogex for the power plant requirements covered by the competitive bid.

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") which is designed to provide for choice by retail customers of their electric supplier by July 1, 2002. In 1998 and 1999, various amendments to the Act were enacted. Additional implementing legislation needs to be adopted by the Oklahoma Legislature to address many specific issues associated with the Act and deregulation. 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:

1. 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, was 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 that 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 recovery of an appropriate amount of prudently incurred, unmitigable and verifiable stranded costs and investments. As part of this process, each entity shall be required to 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, nor 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 was directed to prepare a four-part study. This study, which was completed in 1999, 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 directed 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. This study also was completed in 1999. 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 created the Joint Task Force, which consisted of seven members from the Oklahoma Senate and seven members from the Oklahoma House of Representatives. The Joint Task Force was 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.

The Act was modified during the 1999 session of the Oklahoma Legislature to clarify certain ambiguities by defining key terms in the Act.

Additional implementing legislation needs to be adopted by the Oklahoma Legislature to address many specific issues associated with the Act and with deregulation. In May 2000, a bill addressing the specific issues of deregulation was passed in the Oklahoma State Senate and then was defeated in the Oklahoma House of Representatives. OG&E cannot predict what, if any, legislation will be adopted at the next legislative session. OG&E intends to participate actively in the legislative process and expects the scheduled start date for customer choice of July 1, 2002 to be postponed.

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 April 1999, Arkansas became the 18th state to pass a law ("the Restructuring Law") calling for restructuring of the electric utility industry at the retail level. The Restructuring Law, like the Oklahoma law, would significantly affect OG&E's future operations. OG&E's electric service area includes parts of western Arkansas, including Fort Smith, the second-largest metropolitan market in the state. The Restructuring Law initially targeted customer choice of electricity providers by January 1, 2002. In February 2001, the law was amended to delay the start date of customer choice of electric providers in Arkansas until October 1, 2003, with the APSC having discretion to further delay implementation to October 1, 2005. The Restructuring 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 Restructuring Law permit municipal electric systems to opt in or out, permit recovery of stranded costs and transition costs and require filing of unbundled rates for generation, transmission, distribution and customer service. OG&E filed preliminary business separation plans with the APSC on August 8, 2000. The APSC has established a timetable to establish rules implementing the Arkansas restructuring statutes.

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. In March 2000, the OCC approved the APC Rider for $10.7 million annually. As previously discussed, the purpose of this rider is to credit the Oklahoma retail customers for the completion of the OCC authorized recovery of the premium paid by OG&E when it acquired Enogex in 1986. The APC Rider is applicable to each Oklahoma retail rate schedule to which OG&E's fuel cost adjustment clause applies.

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. 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") 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 was designed to promote competition in the development of wholesale power generation in the electric industry.

Subsequently, 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. Order 889 also 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.

In December 1999, FERC issued Order 2000 to advance the formation of Regional Transmission Organizations ("RTO"). 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. 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. In October 2000, the SPP filed its application with the FERC to become a RTO. OG&E intends to meet its obligation under Order 2000 and under the restructuring law in Arkansas by joining the RTO being formed by the SPP. The transfer of operational control of OG&E's transmission system to a FERC-approved RTO is not expected to significantly impact 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.

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.

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 $29 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 OG&E 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 legislation in Oklahoma and Arkansas, and other factors are expected to significantly increase competition in the electric industry. OG&E has taken steps in the past and intends to take appropriate steps in the future to remain a competitive supplier of electricity. While OG&E is supportive of competition, it believes that all electric suppliers must be required to compete on a fair and equitable basis and OG&E is advocating this position vigorously.

RATE 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 use of electrical energy 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 2000, 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 its 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 assist customers in controlling their costs.

OG&E's 2000 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.

FUEL SUPPLY

During 2000, approximately 74 percent of the OG&E-generated energy was produced by coal-fired units and 26 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 five years, the average cost of fuel used, by type, per million Btu was as follows:

	2000	1999	1998	1997	1996
Coal.............................	$0.87	$0.85	$0.85	$0.84	$0.83
Natural Gas.....................	$4.93	$3.14	$2.83	$3.60	$3.61
Weighted Avg....................	$1.96	$1.54	$1.48	$1.39	$1.45

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 2,531 megawatts, are designed to burn low sulfur western coal. OG&E purchases coal primarily under long-term contracts. During 2000, OG&E purchased 10.2 million tons of coal from the following Wyoming suppliers: Kennecott Energy Company, Thunder Basin Coal Company, Powder River Coal Company, and Triton Coal Company. The combination of all coal 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, which began in the year 2000, OG&E had contracts in place to 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 2001, OG&E utilized a Request for Bid (RFB) to acquire natural gas supplies through June 2002. Successful bids were accepted that are expected to supply approximately 38% of OG&E's annual gas requirements. OG&E will request bids for additional summer gas supplies. The additional gas requirements will be secured through monthly and day-to-day purchases as needed.

In 1993, OG&E began utilizing a natural gas storage facility, that allows OG&E to optimize economic dispatch of its units. This allows OG&E to attain a fuel mix that provides the lowest possible overall cost of fuel.

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"); exploration and production of oil and natural gas ("Exploration and Production"); marketing of natural gas, natural gas liquids, and electricity ("Marketing"); and the gas gathering and interstate gas transmission operations ("Gas Transportation").

For the year ended December 31, 2000, and before elimination of intercompany items between OG&E and Enogex, Enogex's consolidated revenues and net income were approximately $2.1 billion and $19.7 million, respectively.

Recent Actions: In July 2000, Enogex entered into a new contract with OG&E for new gas transportation service not covered by the $33.4 million contract executed in October 1999 that resulted from the competitive bidding process.

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.

The fees charged by Ozark Pipeline ("Ozark") and by NOARK Pipeline Systems, L.P. ("NOARK") 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. Ozark filed a general rate case pursuant to Section 4 of the Natural Gas Act in April 2000, seeking to increase its base rates for transportation services. The rate case was resolved by settlement, which was approved by the FERC in December 2000 for rates effective November 2000. The newly approved maximum lawful rate for Ozark and NOARK is $0.2867 per mmbtu. As a condition of the settlement Ozark rolled the existing AWP rate into the newly approved Ozark rate.

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.

In July 1999, Enogex acquired Transok Holding LLC ("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. 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 2000, Transok's revenues from the PSO and WTU contracts were $10.2 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. With the acquisition of Transok, Enogex is now one of the largest gas processors in the state of Oklahoma. Enogex now owns 11 gas processing plants, with an inlet capacity of over one billion cubic feet per day ("bcfd"), and has ownership interest in two other gas processing plants, with an inlet capacity of 310 million cubic feet per day ("mmcfd"), on a net percentage of ownership basis. The Gas processing operations are conducted through Enogex Products Corporation ("Products") and a subsidiary of Transok. Products has been active since 1968 in the processing of natural gas and marketing of natural gas liquids. The NuStar Joint Venture ("NuStar"), 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. The products extracted from Transok's natural gas stream include marketable ethane, propane, butanes and natural gasoline mix. The residue gas remaining after the liquid products have been extracted consists primarily of ethane and methane. All Transok processing plants are cryogenic expander processing plants capable of recovering or rejecting ethane.

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 produced by Products and Transok are delivered into pipeline facilities of Koch Hydrocarbon ("Koch") and transported to Conway, Kansas and Mont Belvieu, Texas, where they are sold under contract or on the spot market. Ethane, which is produced at all plants except Calumet, is sold under a contract with Equistar Chemicals LP, Dow Hydrocarbons and Resources Inc. and Koch. 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 OGE Energy Resources ("Energy Resources") and Transok. Energy 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. The integration of the Transok and Enogex pipelines has increased gas transportation and provided Energy Resources with a better platform from which to market natural gas.

Energy 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, Energy 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. Energy Resources markets natural gas developed by Enogex Exploration Corporation ("Exploration") when volumes are sufficiently concentrated to justify Energy 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, Energy 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. Energy 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 Energy Resources, the primary factor is the total cost (including transportation fees) that the buyer must pay. Natural gas transported for Energy Resources by Enogex, Transok or NOARK is billed at the same rates charged for comparable third-party transportation. Energy Resources acts as OG&E's natural gas purchasing arm for the natural gas fuel requirements of the OG&E power stations.

Energy Resources also conducts wholesale electric power purchase and reselling operations and has received market-based rate authority from the FERC. See "Electric Operations - Regulation and Rates." During 2000, Energy Resources had approximately 1.1 million Mwh of power sales. Since March 2000, virtually all of the Company's surplus power sales activity has been performed by Energy Resources.

Exploration and Production. The exploration and production activities are conducted through Exploration, which was formed in 1988 primarily to engage in the development and production of oil and natural gas. Exploration focused its early drilling activity in the Antrim Devonian shale trend in the state of Michigan but in recent years has concentrated on drilling opportunities in Oklahoma. As a part of this refocusing, Exploration sold its interests in Texas and Utah during 2000. As of December 31, 2000, Exploration had interests in over 350 active wells and estimated proved reserves of 71,733 MMcfe. The standardized measure of discounted future net cash flow (with related Section 29 tax credits) of Exploration's proved reserves was $182.5 million at December 31, 2000. In 1998, Energy Resources initiated a program of hedging the future gas selling price on a portion of Exploration's net production through commodity futures contracts to cushion against unfavorable monthly price swings.

FINANCE AND CONSTRUCTION

The Company generally meets its cash needs through a combination of 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.

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 2001 through 2003 are estimated as follows:

(dollars in millions)	2001	2002	2003
Electric utility construction expenditures including AFUDC...........	$118.0	$118.0	$118.0
Non-utility construction expenditures and pending acquisitions................	46.0	46.0	46.0
Maturities of long-term debt.............	7.0	115.0	14.3
Total....................................	$171.0	$279.0	$178.3

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, and to some extent, for satisfying maturing debt. Approximately $2.5 million of the Company's construction expenditures budgeted for 2001 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, increasing demand-side management efforts and, if necessary, purchasing power from third parties. OG&E will continue to evaluate these strategies against the construction of additional peaking units or another base-load generating unit. These evaluations will consider, among other things, the amount of capital requirements and the relative cost of fuel supply, compared to other alternatives.

The Company will continue to use short-term borrowings to meet temporary cash requirements. The Company has the necessary approvals to incur up to $400 million in short-term borrowings at any one time. At December 31, 2000, the Company had in place a line of credit for up to $300 million, with $200 million to expire on January 15, 2001, and the remaining $100 million to expire on January 15, 2004. In January 2001, the Company's line of credit for $200 million was renewed, with an expiration date of January 15, 2002.

The Company's financial results continue to depend to a large extent upon the rates OG&E charges customers and the actions of the regulatory bodies that set those rates, 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 $50.5 million during 2001, compared to approximately $47.1 million utilized in 2000. Approximately $2.5 million of the Company's construction expenditures budgeted for 2001 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 affected OG&E beginning in the year 2000. OG&E met the SO2 limits without additional capital expenditures through the purchase of low sulfur coal. In 2000, OG&E's SO2 emissions were well below the allowable limits.

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 2000 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 2000.

Other potential air regulations have emerged that could impact OG&E. On December 14, 2000, the EPA announced that it is appropriate and necessary to regulate mercury emissions from coal-fired utility boilers. If the EPA decides to regulate mercury emissions, limits on the amount of mercury emitted are expected to be finalized by December 2004 with OG&E's compliance required by 2008. Depending upon the final regulations implemented, this could result in significant capital and operating expenditures.

In 1997, the 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 the EPA for further consideration. The EPA appealed the decision to the U.S. Supreme Court and the Supreme Court issued its decision on February 27, 2001. In its decision, the Supreme Court remanded the case to the District of Columbia Court of Appeals, in part, to allow additional challenges to the standards. If the proposed standard is eventually upheld, then it is likely that Tulsa County will fail to meet the new standard for ozone. The EPA has already indicated that in addition to Tulsa County, Muskogee County will also be considered non-attainment because of its impact on Tulsa. If this occurs NOx reductions at OG&E's Muskogee Generating Station could be required. In addition, the 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.

The EPA also has issued regulations concerning regional haze. These regulations are intended to protect visibility in national parks and wilderness areas throughout the United States. In Oklahoma, the Wichita Mountains would be the only area covered under the regulation. Sulfates and nitrate aerosols (both emitted from coal-fired boilers) can lead to the degradation of visibility. Under these regulations, it is possible that controls on emission sources hundreds of miles away from the affected area may be required. The EPA has begun the process of determining what, if any, impact emission sources in Oklahoma have on national parks and wilderness areas. If an impact is determined, then significant capital expenditures could be required for both Sooner and Muskogee Generating Stations.

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 seven percent reduction from the 1990 levels. While it appears that the Senate will not ratify the Kyoto Protocol, momentum is gaining in the federal government for some type of reduction in the level of carbon dioxide emissions. If legislation is passed, it could have a tremendous impact on OG&E's operations by requiring OG&E to significantly reduce the use of coal as a fuel source.'

OG&E has and will continue to seek new pollution prevention opportunities and to evaluate the effectiveness of its waste reduction, reuse and recycling efforts. In 2000, OG&E obtained refunds of approximately $365,000 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 approvals to renew its Oklahoma Pollution Discharge Elimination System ("OPDES") permits for all facilities except one, which is awaiting final 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 that were constructed at one of its existing plants.

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, OG&E could be subjected to costly treatment and/or facility reconfiguration requirements. Both the State and EPA have now approved this request.

OG&E remains a party to one action brought by the EPA concerning cleanup of a disposal site 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 3,032 employees at December 31, 2000.

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 generating stations with an aggregate capability of 5,781 megawatts. The following table sets forth information with respect to 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	503.0	
	5	Coal	1978	500.0	
	6	Coal	1984	516.0	1,690
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	402.0	
	9	Gas	2000	45.0	
	10	Gas	2000	45.0	897
Mustang	1	Gas	1950	56.0	
	2	Gas	1951	53.0	
	3	Gas	1955	118.0	
	4	Gas	1959	258.0	
	5	Gas	1971	63.0	548

Conoco	1	Gas	1991	32.0	
	2	Gas	1991	31.0	63
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 Generating Capability (all stations)					5,781

At December 31, 2000, OG&E's transmission system included: (i) 64 substations with a total capacity of approximately 18 million kVA and approximately 3,996 structure miles of lines in Oklahoma; and (ii) six substations with a total capacity of approximately 2.3 million kVA and approximately 241 structure miles of lines in Arkansas. OG&E's distribution system included: (i) 299 substations with a total capacity of approximately 4.4 million kVA, 22,326 structure miles of overhead lines, 1,739 miles of underground conduit and 7,076 miles of underground conductors in Oklahoma; and (ii) 31 substations with a total capacity of approximately 731,000 kVA, 1,861 structure miles of overhead lines, 198 miles of underground conduit and 411 miles of underground conductors in Arkansas.

Enogex and its subsidiaries own: (i) approximately 9,700 miles of intrastate transmission and gathering lines in the states of Oklahoma and Texas; (ii) 11 natural gas processing plants with a capacity to process over one bcfd, all located in Oklahoma; (iii) 75 percent interest in NOARK, 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 mmcfd; (v) five bcf of gas storage in Oklahoma with a withdrawal capacity of 400 mmcfd; (vi) an 80 percent interest in NuStar, 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 200 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 345 miles of gathering lines in West Texas.

During the three years ended December 31, 2000, the Company's gross property, plant and equipment additions approximated $1.4 billion and gross retirements approximated $163.2 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 38.5 percent of total property, plant and equipment at December 31, 2000.

Item 3. Legal Proceedings.

1. 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.

2. 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 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. Oral argument was heard by the Tenth Circuit on January 22, 2001. A decision is not expected for several months. 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.

3. 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.

4. 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 Plaintiffs appealed the trial court decision and the Court of Appeals upheld the trial court's judgment on all counts. The time for Plaintiffs to appeal the decision to the Supreme Court of Oklahoma has not expired as of the date of this report. The Company continues to believe that this case is without merit.

5. United States of America ex rel., Jack J. Grynberg v. Enogex Inc., Enogex Services Corporation (now, Energy 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. The Court has not yet ruled on the motions to dismiss.

On April 10, 2000, the MDL Panel transferred another *qui tam* case *(Quinque Operating Company, et al. v. Enogex Services Corporation, Enogex, Inc., Transok LLC, Transok, Inc., and Oklahoma Gas & Electric Company, et al.) ("Quinque")* to Judge Downes in Wyoming and the MDL Panel consolidated it with this case.

On July 27, 2000, the Department of Justice ("DOJ") filed a Motion to Dismiss certain of Grynberg's claims on the basis Grynberg was not the first to file such *qui tam* allegations. The DOJ's Motion to Dismiss was heard on February 22, 2001.

On October 6, 2000, the MDL Panel transferred two additional *qui tam* cases *(Harold E. Wright, et al. v. AGIP Petroleum, et al.*, E.D. Texas, C.A. No. 9:98-30 and *M. Glenn Ousterhaudt, III, et al. v. Amoco Production, et al.*, E.D. Texas, C.A. No. 9:98-101) to Judge Downes in Wyoming, and the MDL consolidated them with this case and the *Quinque* case. The Company has not been named as a party in either the *Wright or Ousterhaudt* cases; therefore, no information regarding these two cases is being provided at this time.

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.

6. On September 24, 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 of a possible tag-along action to the Grynberg *qui tam* actions discussed in Item 3, number 4 above. On March 30, 2000, the MDL Panel heard oral argument regarding the transfer of this action as a tag-along case; and on April 10, 2000, the MDL Panel transferred this case to Judge Downes in Wyoming and consolidated it with the Grynberg cases above.

On September 8, 2000, Plaintiffs filed a Motion for Expedited Hearing on Motion to Remand. On January 12, 2001, the Court issued its oral order granting Plaintiff's Motion to Remand. The Court is currently reviewing a Motion to Reconsider before sending the Order to the Stevens County Clerk, effectively remanding the case back to the Kansas State Court.

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, 2001:

Name	Age	Title
Steven E. Moore	54	Chairman of the Board, President and Chief Executive Officer
Al M. Strecker	57	Executive Vice President and Chief Operating Officer
Roger A. Farrell	48	President and Chief Executive

		Officer - Enogex Inc.
James R. Hatfield	43	Senior Vice President and Chief Financial Officer
Jack T. Coffman	57	Senior Vice President - Power Supply - OG&E
Melvin D. Bowen, Jr.	59	Vice President - Power Delivery - OG&E
Michael G. Davis	51	Vice President - Marketing and Customer Care
Irma B. Elliott	62	Vice President and Corporate Secretary
Steven R. Gerdes	44	Vice President - Shared Services
David J. Kurtz	39	Vice President - Business Development
Donald R. Rowlett	43	Vice President and Controller
Don L. Young	60	Controller Corporate Audits
Eric B. Weekes	49	Treasurer

No family relationship exists between any of the Executive Officers of the Registrant. Messrs. Moore, Strecker, Hatfield, Davis, Gerdes, Kurtz, Rowlett, Young, Weekes 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 24, 2001.

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
Al M. Strecker	1998-Present:	Executive Vice President and Chief Operating Officer
	1996-1998:	Senior Vice President
Roger A. Farrell	1998-Present:	President and Chief Executive Officer - Enogex Inc.
	1997-1998:	Executive Vice President - Enogex Inc.
	1996-1997:	Vice President - Business Development - Enogex Inc.
James R. Hatfield	2000-Present:	Senior Vice President and Chief Financial Officer
	1999-2000:	Senior Vice President, Chief Financial Officer and Treasurer
	1997-1999:	Vice President and Treasurer
	1996-1997:	Treasurer - OG&E
Jack T. Coffman	1999-Present:	Senior Vice President - Power Supply - OG&E
	1996-1999:	Vice President - Power Supply - OG&E
Melvin D. Bowen, Jr.	1996-Present:	Vice President - Power Delivery - OG&E
Michael G. Davis	1998-Present:	Vice President - Marketing and Customer Care
	1996-1998:	Vice President - Marketing and Customer Services - OG&E
Irma B. Elliott	1996-Present:	Vice President and Corporate Secretary
Steven R. Gerdes	1998-Present:	Vice President - Shared Services
	1997-1998:	Director - Shared Services
	1997:	Manager - Enterprise Support
	1996-1997:	Manager - Purchasing and Material Management - OG&E
David J. Kurtz	1999-Present:	Vice President - Business Development

	1997-1999:	Vice President - Business Development - Enogex Inc.
	1996-1997:	Director - Gas Supply - Enogex Inc.
Donald R. Rowlett	1999-Present:	Vice President and Controller
	1996-1999:	Controller Corporate Accounting
Don L. Young	1996-Present:	Controller Corporate Audits
Eric B. Weekes	2000-Present:	Treasurer
	1997-2000:	Treasurer - Illinois Power and Light
	1996-1997:	Senior Financial Manager - Kraft Foods Inc.

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.

	2000			1999		
	Dividend Paid	High	Low	Dividend Paid	High	Low
First Quarter	$0.3325	$20.88	$16.50	$0.3325	$29.06	$22.56
Second Quarter	0.3325	21.25	18.31	0.3325	25.94	21.81
Third Quarter	0.3325	23.25	18.75	0.3325	24.56	21.69
Fourth Quarter	0.3325	24.75	18.94	0.3325	23.19	18.50

The number of record holders of Common Stock at December 31, 2000, was 36,326. The book value of the Company's Common Stock at December 31, 2000, was $13.66.

Item 6. Selected Financial Data.

HISTORICAL DATA

	2000	1999	1998	1997	1996
SELECTED FINANCIAL DATA (dollars in thousands except for per share data)					
Operating revenues..................	$ 3,298,727	$ 2,172,434	$ 1,617,737	$ 1,443,610	$ 1,387,435
Operating expenses..................	2,948,906	1,834,269	1,278,280	1,175,160	1,107,989
Operating income....................	349,821	338,165	339,457	268,450	279,446
Other income and (deductions).......	6,383	3,317	5,758	5,047	97
Interest charges....................	132,664	100,279	70,699	66,495	67,984
Net income..........................	147,035	151,259	165,872	132,550	133,332
Preferred dividend requirements......................	---	---	733	2,285	2,302
Earnings available for common...........................	$ 147,035	$ 151,259	$ 165,139	$ 130,265	$ 131,030
Long-term debt......................	$ 1,648,523	$ 1,140,532	$ 935,583	$ 841,924	$ 829,281
Total assets........................	$ 4,319,630	$ 3,921,334	$ 2,983,929	$ 2,765,865	$ 2,762,355
Earnings per average common share.............................	$ 1.89	$ 1.94	$ 2.04	$ 1.61	$ 1.62
CAPITALIZATION RATIOS					
Common equity.......................	39.23%	47.20%	52.72%	52.50%	52.26%
Cumulative preferred stock..........	---	---	---	2.63%	2.68%
Long-term debt......................	60.77%	52.80%	47.28%	44.87%	45.06%
INTEREST COVERAGES					
Before federal income taxes (including AFUDC).................	2.66X	3.39X	4.84X	4.11X	4.07X

(excluding AFUDC).................	2.64X	3.38X	4.82X	4.10X	4.06X
After federal income taxes					
(including AFUDC).................	2.09X	2.50X	3.31X	2.98X	2.94X
(excluding AFUDC).................	2.07X	2.49X	3.30X	2.97X	2.93X

Item 7. Management's Discussion and analysis of Financial Condition and Results of Operations.

Management's Discussion and Analysis

OVERVIEW

(thousands except per share amounts)	2000	1999	1998	Percent Change From Prior Year 2000	1999
Operating revenues..............................	$3,298,727	$2,172,434	$1,617,737	51.8	34.3
Earnings available for common stock............	$ 147,035	$ 151,259	$ 165,139	(2.8)	(8.4)
Average shares outstanding.....................	77,864	77,916	80,772	(0.1)	(3.5)
Earnings per average common share..............	$ 1.89	$ 1.94	$ 2.04	(2.6)	(4.9)
Earnings per average common share - assuming dilution...........................	$ 1.89	$ 1.94	$ 2.04	(2.6)	(4.9)
Dividends paid per share.......................	$ 1.33	$ 1.33	$ 1.33	---	---

OGE Energy Corp. (the "Company") serves as the parent holding company to its two primary subsidiaries, Oklahoma Gas and Electric Company ("OG&E") and Enogex Inc. ("Enogex"). This holding company structure is intended to allow the Company greater flexibility 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. Despite the continuing growth at Enogex, the Company's financial results and condition remain substantially dependent at this time on the financial results and condition of OG&E.

The following discussion and analysis presents factors that 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. Trends and contingencies of a material nature are discussed to the extent known and considered relevant.

The Company reported earnings of $1.89 a share in 2000, a 2.6 percent decrease from $1.94 a share in 1999. Record revenues of $3.3 billion were offset by higher operating and maintenance expenses and increased interest expense.

Enogex contributed $0.25 in earnings per share in 2000, down from $0.28 in 1999. Revenues increased at Enogex due to higher commodity prices and increased gas marketing volumes, as well as greater natural gas transportation and processing volumes reflecting the full year impact of the Transok acquisition in mid 1999. The higher revenues at Enogex were offset by higher gas and electricity purchased for resale, operation and maintenance (including a $25 million increase in under-recovered pipeline fuel expense) and interest expenses. The holding company incurred increased interest expenses, which resulted in a loss of $0.19 per share in 2000, down from a loss of $0.12 per share in 1999.

The reduction in earnings in 2000 was partially offset by higher earnings at OG&E, which contributed $1.83 in earnings per share in 2000, up from $1.78 in 1999. The increase in OG&E's earnings was primarily attributable to higher revenues from kilowatt-hour sales to OG&E electric customers ("system sales") due to more favorable weather in the last six months of 2000. Revenue also increased due to the recovery of higher fuel costs. As described in more detail below, the increase in revenues was only partially offset by state regulatory action that changed the Generation Efficiency Performance Rider ("GEP Rider") and implemented the Acquisition Premium Credit Rider ("APC Rider").

The 1999 decrease in earnings to $1.94 a share from $2.04 a share in 1998 was primarily the result of lower revenues at OG&E due to milder weather, lower recoveries under the GEP Rider and less revenue from sales to other utilities and power marketers ("off-system sales"). The decrease in earnings was partially offset by significantly higher earnings at Enogex, and benefits resulting from the Company repurchasing 3 million shares of its common stock in January 1999.

The dividend payout ratio (expressed as a percentage of earnings available for common shareholders) was 70 percent in 2000 as compared to 69 percent in 1999, 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.

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 electric suppliers by July 1, 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 law initially targeted customer choice of electricity providers by January 1, 2002, but the law was amended to delay customer choice until October 1, 2003. It now appears that customer choice of electric suppliers may also be delayed in Oklahoma beyond 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 the 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 assets also include nine gas-processing plants. Enogex purchased Transok for $710.3 million, which includes assumption of $173 million of long-term debt.

In December 2000, the Company announced that Enogex's natural gas pipeline business signed two long-term contracts with third parties to transport 100 percent of the natural gas to fuel a new 1,100 megawatt power plant under construction in Coweta, Oklahoma, near Tulsa in northeastern Oklahoma, and to transport 100 percent of the natural gas to fuel a new 800 megawatt power plant under construction in Jenks, Oklahoma. These two new facilities will be connected to the Transok pipeline system, operated by Enogex. The new power plant in Coweta, Oklahoma is designed to burn up to 185 million cubic feet of natural gas per day. Testing is scheduled to begin in November 2001, with full commercial operation expected in June 2002. The new power plant in Jenks, Oklahoma is designed to burn up to 150 million cubic feet of natural gas per day. Testing is scheduled to begin May 2001 and full commercial operation is expected to begin in January 2002. These are the type of growth opportunities envisioned by the Company when Transok was acquired in 1999. The Company will continue to pursue these kinds of projects as deregulation of electricity and natural gas encourage further development of the energy infrastructure in our region.

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 including the extent and timing of the entry of additional competition in the markets served by the Company; unusual weather; state and federal legislative and regulatory decisions and initiatives that affect cost and investment recovery, have an impact on rate structures and affect the speed and degree to which competition enters the Company's markets; and the other risk factors listed in the reports filed by the Company with the Securities and Exchange Commission.

Results of Operations

REVENUES

(thousands)	2000	1999	1998	Percent Change From Prior Year 2000	Percent Change From Prior Year 1999
Sales of electricity to OG&E customers....	$ 1,440,637	$ 1,258,950	$ 1,274,643	14.4	(1.2)
Off-system sales..........................	12,948	27,894	37,435	(53.6)	(25.5)
Enogex....................................	1,845,142	885,512	304,694	108.4	190.6
Miscellaneous.............................	---	78	965	(100.0)	(91.9)
Total operating revenues............	$ 3,298,727	$ 2,172,434	$ 1,617,737	51.8	34.3
System megawatt-hour sales................	25,001,686	23,468,130	23,642,599	6.5	(0.7)
Off-system megawatt-hour sales............	256,358	374,027	727,601	(31.5)	(48.6)
Total megawatt-hour sales............	25,258,044	23,842,157	24,370,200	5.9	(2.2)

In 2000, approximately 56 percent of the Company's revenues consisted of the non-utility operations of Enogex, while the remaining 44 percent were provided by the regulated sales of electricity by OG&E as a public utility. 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. While the marketing activities of Enogex represented $1.3 billion of Enogex's revenues in 2000, this activity had relatively low operating margins and less impact on earnings than other portions of Enogex's business. Revenues from the 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. 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 Oklahoma Corporation Commission ("OCC") actions relating to these transportation fees.

Operating revenues increased $1.1 billion or 51.8 percent during 2000, largely attributable to significantly increased Enogex revenues. In 2000, Enogex's revenues increased $959.6 million or 108.4 percent largely due to the inclusion of a full year of revenues from Transok's operations and to higher commodity prices and greater natural gas marketing, transportation and processing volumes. The integration of the Transok and Enogex pipelines has increased gas transportation revenue and provided Enogex's energy marketing unit with a better platform from which to market natural gas.

OG&E revenues increased $166.7 million or 13 percent primarily attributable to warmer weather in the third quarter and colder weather in the fourth quarter in OG&E's electric service area and the recovery of higher fuel costs. The favorable weather was primarily responsible for a 14.4 percent increase in revenue from system sales. The increased revenue from system sales was partially offset by a 53.6 percent decrease in revenue from off-system sales. The decline in revenue from off-system sales resulted from a reduction in both volumes and prices. OG&E revenues were also adversely affected by the actions of the OCC in lowering recoveries by $10.9 million under the GEP Rider and implementing the APC Rider, which reduced revenues by $10.2 million. OG&E's revenues in 2000 also were affected by a $2.3 million annual reduction of its rates in Arkansas, which became effective in August 1999. See Note 11 of Notes to Consolidated Financial Statements for a more detailed discussion of these matters.

During 1999, revenues increased $554.7 million or 34.3 percent due to a significant increase in revenue from Enogex. In 1999, Enogex's 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 system sales and off-system sales, both of which were higher in 1998 because of the record heat experienced in the summer of 1998. Lower recoveries under the GEP Rider also contributed to lower revenues at OG&E.

EXPENSES AND OTHER ITEMS

(dollars in thousands)	2000	1999	1998	Percent Change From Prior Year 2000	Percent Change From Prior Year 1999
Fuel	$ 451,613	$ 309,327	$ 315,194	46.0	(1.9)
Purchased power....................................	263,328	249,203	240,542	5.7	3.6
Gas and electricity purchased for resale (Enogex)...	1,458,085	672,281	216,432	116.9	210.6
Other operation and maintenance.....................	536,751	382,235	305,106	40.4	25.3
Depreciation and amortization.......................	176,144	165,041	149,818	6.7	10.2
Taxes other than income.............................	62,985	56,182	51,188	12.1	9.8
Total operating expenses.......................	$2,948,906	$1,834,269	$1,278,280	60.8	43.5
Total other income (expenses)..................	$ (126,281)	$ (96,962)	$ (64,941)	30.2	49.3
Provision for income taxes.....................	$ 76,505	$ 89,944	$ 108,644	(14.9)	(17.2)

Total operating expenses increased $1.1 billion or 60.8 percent in 2000, primarily due to increased sales volumes, rising commodity prices, and the full year impact of the Transok acquisition in July 1999.

Enogex's gas and electricity purchased for resale pursuant to its energy-marketing operations increased $785.8 million or 116.9 percent in 2000 as compared to $455.8 million or 210.6 percent for 1999. The 2000 increase was due to natural gas resale activity associated with Transok's operations ($243.6 million), increased natural gas prices and increased volumes in the marketing of natural gas. The 1999 increase was due to a significant increase in sales volumes of natural gas, the Transok acquisition in mid 1999, and increased power marketing sales.

Other operation and maintenance increased $154.5 million or 40.4 percent in 2000 primarily because of the July 1999 Transok acquisition ($126.0 million), increased natural gas purchases for operations ($14.6 million), higher employee benefit costs ($13.1 million) and higher labor costs ($6.6 million). The increase in expenses included $25 million of under-recovered pipeline system fuel expenses at Enogex. Enogex has, among other actions, filed for fuel rate adjustments with the Federal Energy Regulatory Commission ("FERC") to recoup certain prior fuel costs and to more accurately recover fuel costs in the future. In 1999, other operation and maintenance expenses increased $77.1 million or 25.3 percent 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).

OG&E's electric generating capability is fairly evenly divided between coal and natural gas and provides for flexibility to use either fuel to the best economic advantage for OG&E and its customers. Despite this flexibility (OG&E's fuel mix was 74 percent low-cost coal and 26 percent natural gas in 2000), fuel costs increased $142.3 million or 46.0 percent in 2000, primarily due to a 29.9 percent increase in the average cost of fuel burned for generation of electricity and a 7.1 percent increase in total energy generated. During 1999, fuel costs decreased $5.9 million or 1.9 percent due to a 3.4 percent decrease in total generation, which offset a 1.9 percent 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. See Note 11 of Notes to Consolidated Financial Statements.

OG&E's purchased power costs increased $14.1 million or 5.7 percent in 2000 primarily due to a 9.5 percent increase in the cost of purchased energy per kwh, which offsets a 4.3 percent reduction in total energy purchased. During 1999, purchased power costs increased $8.7 million or 3.6 percent 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. As required by the Public Utility Regulatory Policy Act ("PURPA"), OG&E is currently purchasing power from qualified cogeneration facilities. See Note 10 of Notes to Consolidated Financial Statements.

Depreciation and amortization expenses increased $11.1 million or 6.7 percent, and $15.2 million or 10.2 percent in 2000 and 1999, respectively, reflecting increased levels of depreciable plant, primarily property of Transok.

Interest expense increased $32.4 million or 32.3 percent in 2000 primarily due to increased long-term debt at Enogex as a result of the Transok acquisition and due to interest costs on the trust preferred securities issued in October 1999. The proceeds from the increased long-term debt and trust preferred securities were used to repay short-term debt incurred to finance the Transok acquisition. In 1999, interest expense increased $29.6 million or 41.8 percent due to higher interest charges at Enogex and costs associated with increased short-term debt incurred to finance the Transok acquisition.

Liquidity and Capital Resources

The primary capital requirements for 2000 and as estimated for 2001 through 2003 are as follows:

(dollars in millions)	2000	2001	2002	2003
Electric utility construction expenditures including AFUDC..........	$128.4	$118.0	$118.0	$118.0
Non-utility construction expenditures and acquisitions.......................	51.1	46.0	46.0	46.0
Maturities of long-term debt............	169.0	7.0	115.0	14.3
Total...................................	$348.5	$171.0	$279.0	$178.3

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.

2000 CAPITAL REQUIREMENTS AND FINANCING ACTIVITIES

Capital requirements were $348.5 million in 2000. Approximately $4.4 million of the 2000 capital requirements were to comply with environmental regulations. This compares to capital requirements of $729.9 million in 1999, of which $2.0 million was to comply with environmental regulations. During 2000, the Company's sources of capital were internally generated funds from operating cash flows, permanent financing and short-term borrowings. The increases in accounts receivable and accounts payable, in 2000, are reflective of increased levels of activity by the Enogex marketing unit and also reflective of the significant increases in the cost of natural gas at both OG&E and Enogex.

Short-term borrowings were used during 2000 to meet temporary cash requirements. At December 31, 2000, the Company had outstanding short-term borrowings of $284.5 million.

On October 15, 2000, a $110 million series of OG&E's 6.25 percent Senior Notes matured. OG&E temporarily funded this transaction through short-term borrowings from the Company. On October 23, 2000, OG&E issued $110 million of 7.125 percent Senior Notes, Series due October 15, 2005. Net proceeds from this transaction were used to repay the temporary short-term borrowings from the Company.

OG&E acquired two gas turbine generators for use at its Horseshoe Lake Generating Station. These two generators began operation on June 14 and July 16, 2000. Each generator can produce approximately 45 megawatts of additional peak-load generating capacity. The total cost of this project was approximately $45 million.

On July 21, 2000, OG&E reactivated two of its generators, which had been idle for several years, at its Mustang Generating Station. These two generators together produce approximately 109 megawatts of additional peak-load generating capacity. The total cost of this reactivation project was approximately $5 million. Together, these four generators at Horseshoe Lake and Mustang increased OG&E's electric generating capacity by approximately 4 percent.

As discussed previously, on July 1, 1999, Enogex completed its acquisition of Transok for $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 credit agreement with a consortium of banks with Bank One, N.A. serving as agent. On October 21, 1999, the financing trust subsidiary of the Company 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 credit agreement implemented in connection with the Transok acquisition.

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 one year interest rate swap agreements to manage interest costs associated with this $400 million issue. During 2000, the effect of these swap agreements reduced the overall effective interest rate from 8.125 percent to 6.6875 percent. The interest rate swaps expired in January 2001. Enogex used the proceeds from the issuance of this new debt to repay the Company for the temporary short-term debt associated with the Transok acquisition and for general corporate purposes.

Enogex used cash flow from operations to retire $57 million of long-term debt that matured in the third quarter of 2000. This debt consisted of $23 million principal amount of 6.77 percent medium-term notes due August 7, 2000, $4 million principal amount of 6.76 percent medium-term notes due August 7, 2000, $20 million principal amount of 6.68 percent medium-term notes due August 31, 2000, and $10 million principal amount of 6.70 percent medium-term notes due September 1, 2000. Enogex is expected to continue reducing its outstanding long-term debt during 2001. Enogex retired $5 million of long-term debt in January 2001.

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 and increasing the utilization of existing capacity, increasing demand-side management efforts and, if necessary, purchasing power from third parties. OG&E will continue to evaluate these strategies against the construction of additional peaking units or another base-load generating unit. These evaluations will consider, among other things, the amount of capital requirements and the relative cost of fuel supply, compared to other alternatives. Approximately $2.5 million of the Company's construction expenditures budgeted for 2001 are to comply with environmental laws and regulations.

The Company will continue to pursue a convergence strategy for its electricity and natural gas businesses. This strategy seeks to maximize the value of the Company's power plants and gas pipelines by coordinating, consistent with regulatory requirements, their activities through its marketing, trading and energy-services unit.

As discussed in Note 8 of Notes to Consolidated Financial Statements, the Company recently made several changes to its pension plan, including the addition of a cash balance benefit feature. The cash balance plan may provide lower post-employment pension benefits to employees, which could result in less pension expense being recorded. Over the near term, the Company's cash requirements for the plan are not expected to be materially different than the requirements existing prior to the plan changes. However, as the population of employees included in the cash balance plan feature increases, the Company's cash requirements may be materially different than the requirements under the Company's prior pension plan.

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. Short-term borrowings will continue to be used to meet temporary cash requirements. The Company has the necessary approvals to incur up to $400 million in short-term borrowings at any one time. At December 31, 2000, the Company had in place a line of credit for up to $300 million, with $200 million to expire on January 15, 2001, and the remaining $100 million to expire on January 15, 2004. In January 2001, the Company's line of credit for $200 million was renewed, with an expiration date of January 15, 2002.

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.

ELECTRIC COMPETITION; REGULATION

As previously reported, Oklahoma enacted in April 1997 the Electric Restructuring Act of 1997 (the "Act"), which is designed to provide for choice by retail customers of their electric supplier by July 1, 2002. Various amendments to the Act were enacted in 1998 and 1999. Additional implementing legislation needs to be adopted by the Oklahoma Legislature to address many specific issues associated with the Act and with deregulation. If implemented as proposed, the Act will significantly affect OG&E's future operations.

The stated purpose of the Act 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 completed in 1999.

Neither the Oklahoma Tax Commission nor the OCC is authorized under the Act to issue any rules on such matters without the approval of the Oklahoma Legislature. Other provisions of the Act, (i) prohibit customer switching prior to July 1, 2002, except by mutual consent, (ii) 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, (iii) require a uniform tax policy be established by July 1, 2002 and (iv) 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.

As discussed above, additional implementing legislation needs to be adopted by the Oklahoma Legislature to address many specific issues associated with the Act and with deregulation. In May 2000, a bill addressing the specific issues of deregulation was passed in the Oklahoma State Senate and then was defeated in the Oklahoma House of Representatives. The Company cannot predict what, if any, legislation will be adopted at the next legislative session. The Company will participate actively in the legislative process and expects the scheduled start date for customer choice of July 1, 2002, to be postponed.

In April 1999, Arkansas became the 18th state to pass a law ("the Restructuring Law") calling for restructuring of the electric utility industry at the retail level. The Arkansas Restructuring Law, like the Oklahoma law, would significantly affect OG&E's future operations. OG&E's electric service area includes parts of western Arkansas, including Fort Smith, the second-largest metropolitan market in the state. The Restructuring Law initially targeted customer choice of electricity providers by January 1, 2002. In February 2001, the law was amended to delay the start date of customer choice of electric providers in Arkansas until October 1, 2003, with the APSC having discretion to further delay implementation to October 1, 2005. The Restructuring 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 Restructuring Law permit municipal electric systems to opt in or out, permit recovery of stranded costs and transition costs and require filing of unbundled rates for generation, transmission, distribution and customer service. OG&E filed preliminary business separation plans with the APSC on August 8, 2000. The APSC established a timetable to establish rules implementing the Arkansas restructuring statutes.

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. The rules are expected to offer increased opportunities to Enogex's pipeline and related businesses.

The efforts to increase competition in the electric industry at the retail 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. The National Energy Policy Act of 1992 ("Energy Act"), among other things, promoted the development of independent power producers ("IPPs"). The Energy Act was followed by FERC Order 888 and Order 889, which facilitated third-party utilization of the transmission grid for sales of wholesale power.

The Energy Act, Orders 888 and 889, and other FERC policies and initiatives have significantly increased competition in the wholesale power market. Utilities, including OG&E, have increased their own in-house wholesale marketing efforts and the number of entities with whom they 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: (i) engineering and economic inefficiencies inherent in the current operation and expansion of the transmission grid and (ii) continuing opportunities for transmission owners (primarily electric utilities) to discriminate in the operation of their transmission facilities in favor of their own or affiliated power marketing activities. 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 is intended to have the effect of turning the nation's transmission facilities into independently operated "common carriers" that offer comparable service to all would-be-users. Although adopting a voluntary approach towards RTO formation, FERC stressed that Order 2000 does not preclude it from requiring RTO participation. 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 an RTO, the reasons for not participating in an RTO proposal and any obstacles to participation, and its plans for further work toward participation.

OG&E is a member of the Southwest Power Pool ("SPP"), the regional reliability organization for 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. In October 2000, the SPP filed its application with the FERC to become an RTO. OG&E intends to meet its obligations under Order 2000 and under the restructuring law in Arkansas by joining the RTO being formed by the SPP. The transfer of operational control of OG&E's transmission system to a FERC-approved RTO is not expected to significantly impact 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 $29 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.

On January 12, 2000, the OCC Staff (the "Staff") filed three applications to address various aspects of OG&E's electric rates. See Note 11 of Notes to Consolidated Financial Statements for a discussion of these matters.

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 certain commodity prices and interest rates.

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)	2001	2002	2003	2004	2005	Thereafter	Total	2000 Year-end Fair Value
Fixed rate debt:								
Principal amount.........	$ 7.0	$115.0	$ 14.3	$ 57.8	$152.9	$ 1,170.9	$1,517.9	$1,550.0
Weighted-average interest rate..........	7.15%	7.34%	7.70%	7.20%	7.09%	7.57%	7.34%	---
Variable-rate debt:								
Principal amount.........	---	---	---	---	---	$ 135.4	$ 135.4	$ 135.4
Weighted-average interest rate..........	---	---	---	---	---	4.25%	4.25%	---

COMMODITY PRICE EXPOSURE

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

The prices of natural gas, natural gas liquids 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). See "Price Risk Management Activities" in Note 1 of Notes to Consolidated Financial Statements. 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, natural gas liquids 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 market prices. Market risk is estimated as the potential loss in fair value resulting from a hypothetical 10 percent adverse change in such prices over the next 12 months. The results of this analysis, which may differ from actual results, are as follows for fiscal 2001:

(dollars in thousands)	Wholesale	Non-Trading
Commodity market risk, net.......	$ 3,138	$ 6,249

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. In June 2000, the FASB issued SFAS No. 138, "Accounting for Certain Derivative Instruments and Certain Hedging Activities", which amends the accounting and reporting standards of SFAS No. 133 for certain derivative instruments and hedging activities. 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. During 2000, the Company established an SFAS No. 133 implementation team that reviewed contracts throughout the Company identifying both freestanding and embedded derivatives which met the criteria set forth in SFAS No. 133 and SFAS No. 138. The Company adopted the new standards effective January 1, 2001. On January 1, 2001, the Company redesignated all of its hedging relationships and recognized all derivatives at their fair value in accordance with SFAS No. 133 and SFAS No. 138. As a result of adopting these standards the Company recorded a cumulative effect transition adjustment debit to Other Comprehensive Income of approximately $26.9 million.

CONTINGENCIES

The Company through its subsidiaries is defending various claims and legal actions, including environmental actions, which are common to its operations. The Company's subsidiaries, primarily OG&E, also could be impacted by various proposed environmental regulations that if adopted, could result in significant increases in capital expenditures and operating expenses. For a further discussion of these matters, 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 a waste disposal site to which OG&E sent materials. While it is not possible to determine the precise outcome of this matter, in the opinion of management, OG&E's ultimate liability for this site will not be material.

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.

2001 OUTLOOK

The Company expects that earnings in 2001 will be at $2.00 to $2.10 per share. Earnings growth is expected primarily from improved performance at Enogex.

Item 8. Financial Statements and Supplementary Data.

CONSOLIDATED BALANCE SHEETS

December 31 (dollars in thousands)	2000	1999	1998

ASSETS

CURRENT ASSETS:			
Cash and cash equivalents	$ 454	$ 7,271	$ 378
Accounts receivable - customers, less reserve of $4,135, $5,270 and $3,342, respectively	446,185	263,708	141,235
Accrued unbilled revenues	49,000	40,200	22,500
Accounts receivable - other	24,713	10,462	12,902
Fuel inventories	200,316	117,185	57,288
Materials and supplies, at average cost	41,517	39,194	29,734
Prepayments and other	45,715	12,328	30,753
Price risk management	45,727	4,583	798
Accumulated deferred tax assets	10,669	8,729	7,811
Total current assets	864,296	503,660	303,399
OTHER PROPERTY AND INVESTMENTS, at cost	36,980	31,012	31,682
PROPERTY, PLANT AND EQUIPMENT:			
In service	5,323,541	5,209,783	4,391,232
Construction work in progress	47,016	56,553	50,039
Total property, plant and equipment	5,370,557	5,266,336	4,441,271
Less accumulated depreciation	2,151,093	2,024,349	1,914,721
Net property, plant and equipment	3,219,464	3,241,987	2,526,550
DEFERRED CHARGES:			
Advance payments for gas	12,500	11,800	15,000
Income taxes recoverable through future rates	38,654	39,692	40,731
Other	147,736	93,183	66,567
Total deferred charges	198,890	144,675	122,298
TOTAL ASSETS	$4,319,630	$3,921,334	$2,983,929

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

CONSOLIDATED BALANCE SHEETS (Continued)

December 31 (dollars in thousands)	2000	1999	1998
LIABILITIES AND STOCKHOLDERS' EQUITY			
CURRENT LIABILITIES:			
Short-term debt	$ 284,500	$ 589,100	$ 119,100
Accounts payable	330,445	161,183	96,936
Dividends payable	25,890	25,889	26,865
Customers' deposits	22,647	22,138	23,985
Accrued taxes	33,067	41,215	30,500
Accrued interest	40,699	28,191	21,081
Long-term debt due within one year	2,000	169,000	2,000
Price risk management	33,709	1,297	4,645
Other	36,975	38,848	30,721
Total current liabilities	809,932	1,076,861	355,833
LONG-TERM DEBT	1,648,523	1,140,532	935,583
DEFERRED CREDITS AND OTHER LIABILITIES:			
Accrued pension and benefit obligation	14,256	16,686	17,952
Accumulated deferred income taxes	618,360	566,137	531,940
Accumulated deferred investment tax credits	57,429	62,578	67,728
Other	106,822	39,161	31,511
Total deferred credits and other liabilities	796,867	684,562	649,131
STOCKHOLDERS' EQUITY:			
Common stockholders' equity	443,298	441,847	513,614
Retained earnings	621,010	577,532	529,768
Total stockholder's equity	1,064,308	1,019,379	1,043,382
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$4,319,630	$3,921,334	$2,983,929

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

CONSOLIDATED STATEMENTS OF CAPITALIZATION

December 31 (dollars in thousands)	2000	1999	1998
COMMON STOCK AND RETAINED EARNINGS:			
Common stock, par value $0.01 per share, authorized 125,000,000 shares; and outstanding 77,921,997, 77,863,370, and 80,797,539 shares, respectively	$ 779	$ 779	$ 808
Premium on capital stock	442,519	441,068	512,806
Retained earnings	621,010	577,532	529,768
Total common stock and retained earnings	1,064,308	1,019,379	1,043,382
LONG-TERM DEBT:			
SERIES DATE DUE			
6.250% Senior Notes, Series Due October 15, 2000	---	110,000	110,000
7.125% Senior Notes, Series Due October 15, 2005	110,000	---	---
6.500% Senior Notes, Series Due July 15, 2017	125,000	125,000	125,000
7.300% Senior Notes, Series Due October 15, 2025	110,000	110,000	110,000
6.650% Senior Notes, Series Due July 15, 2027	125,000	125,000	125,000
6.500% Senior Notes, Series Due April 15, 2028	100,000	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	(2,818)	(2,354)	(2,488)
Enogex Inc. notes (Note 6)	574,941	233,486	234,671
Transok Holding LLC (Note 6)	173,000	173,000	---
Trust Originated Preferred Securities (Note 5)	200,000	200,000	---
Total long-term debt	1,650,523	1,309,532	937,583
Less long-term debt due within one year	2,000	169,000	2,000
Total long-term debt (excluding long-term debt due within one year)	1,648,523	1,140,532	935,583
Total Capitalization	$2,712,831	$2,159,911	$1,978,965

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)	2000	1999	1998
OPERATING REVENUES	$3,298,727	$2,172,434	$1,617,737
OPERATING EXPENSES:			
Fuel	451,613	309,327	315,194
Purchased power	263,328	249,203	240,542
Gas and electricity purchased for resale	1,458,085	672,281	216,432
Other operation and maintenance	536,751	382,235	305,106
Depreciation and amortization	176,144	165,041	149,818
Taxes other than income	62,985	56,182	51,188
Total operating expenses	2,948,906	1,834,269	1,278,280
OPERATING INCOME	349,821	338,165	339,457
OTHER INCOME, NET	2,595	480	2,197
EARNINGS BEFORE INTEREST AND TAXES	352,416	338,645	341,654
INTEREST INCOME (EXPENSES):			
Interest income	3,788	2,837	3,561
Interest on long-term debt	(101,452)	(60,727)	(60,856)
Interest on trust preferred securities	(17,268)	(3,358)	---
Other interest charges	(13,944)	(36,194)	(9,843)
Net interest income (expenses)	(128,876)	(97,442)	(67,138)

EARNINGS BEFORE INCOME TAXES	223,540	241,203	274,516
INCOME TAX EXPENSE	76,505	89,944	108,644
NET INCOME	147,035	151,259	165,872
PREFERRED DIVIDEND REQUIREMENTS	---	---	733
EARNINGS AVAILABLE FOR COMMON STOCK	$ 147,035	$ 151,259	$ 165,139
AVERAGE COMMON SHARES OUTSTANDING (thousands)	77,864	77,916	80,772
EARNINGS PER AVERAGE COMMON SHARE	$ 1.89	1.94	$ 2.04
AVERAGE COMMON SHARES OUTSTANDING ASSUMING DILUTION (thousands)	77,688	77,831	80,787
EARNINGS PER AVERAGE COMMON SHARE ASSUMING DILUTION	$ 1.89	1.94	$ 2.04

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

CONSOLIDATED STATEMENTS OF RETAINED EARNINGS

Year ended December 31 (dollars in thousands)	2000	1999	1998
BALANCE AT BEGINNING OF PERIOD	$ 577,532	$ 529,768	$ 472,063
ADD - net income	147,035	151,259	165,872
Total	724,567	681,027	637,935
DEDUCT:			
Cash dividends declared on preferred stock	---	---	733
Cash dividends declared on common stock	103,557	103,495	107,434
Total	103,557	103,495	108,167
BALANCE AT END OF PERIOD	$ 621,010	$ 577,532	$ 529,768

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

CONSOLIDATED STATEMENTS OF CASH FLOWS

Year ended December 31 (dollars in thousands)	2000	1999	1998
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net Income	$ 147,035	$ 151,259	$ 165,872
Adjustments to Reconcile Net Income to Net Cash Provided from Operating Activities:			
Depreciation and amortization	176,144	165,041	149,818
Deferred income taxes and investment tax credits, net	46,999	31,093	23,922
Gain on sale of assets	(4,820)	---	---
Change in Certain Current Assets and Liabilities:			
Accounts receivable - customers	(182,477)	(69,875)	(23,875)
Accrued unbilled revenues	(8,800)	(17,700)	14,400
Fuel, materials and supplies inventories	(85,454)	(25,049)	(9,223)
Other current assets	(90,724)	16,274	(26,513)
Accounts payable	169,262	9,668	19,203
Accrued taxes	(8,148)	10,715	8,823
Accrued interest	12,508	7,110	1,040
Other current liabilities	31,048	(48,451)	(3,577)
Other operating activities	8,796	(5,832)	(28,103)
Net cash provided from operating activities	211,369	224,253	292,269
CASH FLOWS FROM INVESTING ACTIVITIES:			
Capital expenditures	(179,471)	(181,163)	(235,231)
Proceeds from sale of assets	23,573	---	---
Acquisition of Transok	---	(531,767)	---
Other investing activities	637	2,832	(8,084)
Net cash used in investing activities	(155,261)	(710,098)	(243,315)
CASH FLOWS FROM FINANCING ACTIVITIES:			

Retirement of long-term debt	(168,545)	(2,000)	(113,500)
Proceeds from long-term debt	510,000	---	100,000
Increase (decrease) in short-term debt, net	(304,600)	470,000	118,100
Issuance (retirement) of common stock	1	(30)	---
Premium on issuance (retirement) of common stock	1,450	(71,737)	---
Issuance of trust originated preferred securities	---	200,000	---
Redemption of preferred stock	---	---	(49,266)
Contribution from minority interest	2,590	---	---
Payment of obligation under capital lease	(264)	---	---
Cash dividends declared on preferred stock	---	---	(733)
Cash dividends declared on common stock	(103,557)	(103,495)	(107,434)
Net cash (used in) provided from financing activities	(62,925)	492,738	(52,833)
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	(6,817)	6,893	(3,879)
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	7,271	378	4,257
CASH AND CASH EQUIVALENTS AT END OF PERIOD	$ 454	$ 7,271	$ 378
SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION			
Cash Paid During the Period for:			
Interest (net of amount capitalized)	$ 105,288	$ 76,047	$ 59,792
Income taxes	$ 48,680	$ 52,428	$ 77,150
NON-CASH INVESTING AND FINANCING ACTIVITIES			
Capital lease financing	$ ---	$ ---	$ 9,818
Debt assmed in acquisition	$ ---	$ 173,000	$ 80,000
Other investing and financing activities	$ 2,400	$ 3,182	$ (3,000)
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. and subsidiaries ("Enogex") and OGE Energy Capital Trust I. 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.

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, 2000, regulatory assets and regulatory liabilities are being amortized and reflected in rates charged to customers over periods up to 20 years.

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

Other Deferred Charges and Credits

(dollars in thousands)	2000	1999	1998
Electric Utility Deferred Charges:			
Generating stations	$ 420	$ 4,654	$ ---
Unamortized debt expense	5,565	5,196	8,566
Unamortized loss on reacquired debt	25,644	27,281	29,072
Miscellaneous	4,471	4,116	2,217
Total electric utility deferred charges	36,100	41,247	39,855
Non-Electric Utility Deferred Charges:			
Enogex gas sales contracts	8,832	10,891	12,389
Enogex pipeline over-deliveries	68,510	14,263	3,926
Unamortized debt expense	13,141	10,008	2,954
Enogex minority interest asset	4,838	6,845	---
Miscellaneous	16,315	9,929	7,443
Total non-electric utility deferred charges	111,636	51,936	26,712

Total Deferred Charges	147,736	93,183	66,567
Electric Utility Deferred Credits:			
Take or pay gas litigation	12,.500	11,800	15,000
Miscellaneous	---	133	4,768
Total electric utility deferred credits	12,500	11,933	19,768
Non-Electric Utility Deferred Credits:			
Enogex pipeline under-deliveries	68,182	5,072	2,054
Miscellaneous	26,140	22,156	9,689
Total non-electric utility deferred credits	94,322	27,228	11,743
Total Deferred Credits	$ 106,822	$ 39,161	$ 31,511

Regulatory Assets and Liabilities

(dollars in thousands)	2000	1999	1998
Regulatory Assets:			
Income taxes recoverable from customers	$ 83,617	$ 93,888	$104,160
Unamortized loss on reacquired debt	25,644	27,281	29,072
Miscellaneous	4,471	4,116	2,217
Total Regulatory Assets	113,732	125,285	135,449
Regulatory Liabilities:			
Income taxes refundable to customers	(44,963)	(54,196)	(63,429)
Net Regulatory Assets	$ 68,769	$ 71,089	$ 72,020

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 June 1998, the FASB issued 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. In June 2000, the FASB issued SFAS No. 138, "Accounting for Certain Derivative Instruments and Certain Hedging Activities", which amends the accounting and reporting standards of SFAS No. 133 for certain derivative instruments and hedging activities. 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. During 2000, the Company established an SFAS No. 133 implementation team that reviewed contracts throughout the Company identifying both freestanding and embedded derivatives which met the criteria set forth in SFAS No. 133 and SFAS No. 138. The Company adopted the new standards effective January 1, 2001. On January 1, 2001, the Company redesignated all of its hedging relationships and recognized all derivatives at their fair value in accordance with SFAS No. 133 and SFAS No. 138. As a result of adopting these standards the Company recorded a cumulative effect transition adjustment debit to Other Comprehensive Income of approximately $26.9 million.

PRICE RISK MANAGEMENT ACTIVITIES

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 are 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 3.1 percent of the average depreciable utility plant for 2000, and 3.2 percent for 1999 and 1998, is provided on a straight-line method over the estimated service life of the property. Depreciation is provided at the unit level for production plant and at the account or sub-account level for all other plant, and is based on the average life group method.

Enogex'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 6.68, 5.36 and 5.75 percent for the years 2000, 1999 and 1998, respectively.

FAIR VALUE OF FINANCIAL INSTRUMENTS

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

CASH AND CASH EQUIVALENTS

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

The Company's cash management program utilizes controlled disbursement banking arrangements. Outstanding checks in excess of cash balances totaled $25.0 million, $11.7 million and $27.8 million at December 31, 2000, 1999 and 1998, 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 72 months. The finance rate is based upon short-term loan rates and is reviewed and updated periodically. The interest rates were 10.99, 8.99 and 8.25 percent at December 31, 2000, 1999 and 1998, respectively.

The current portion of these loans totaled $1.5 million, $0.6 million and $1.0 million at December 31, 2000, 1999 and 1998, respectively, and are classified as accounts receivable - customers in the accompanying Consolidated Balance Sheets. The noncurrent portion of these loans totaled $5.9 million, $2.3 million and $4.0 million at December 31, 2000, 1999 and 1998, 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. In March 2000, the OCC approved the Acquisition Premium Credit Rider ("APC Rider") for $10.7 million annually. The purpose of this rider is to credit the Oklahoma retail customers for the completion of the OCC authorized recovery of the premium paid by OG&E when it acquired Enogex in 1986. The APC Rider is applicable to each Oklahoma retail rate schedule to which OG&E's fuel cost adjustment clause applies.

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 higher than the stated LIFO cost by approximately $11.6 million for 2000 and lower than the stated LIFO cost by approximately $0.9 million for 1999 and $4.4 million for 1998, based on the average cost of fuel purchased late in the respective years. Natural gas products inventories used in Enogex's energy trading activities and accounted for under the FASB Emerging Issues Task Force Issue No. 98-10, "Accounting for Contracts Involved in Energy Trading and Risk Management Activities," are valued at market.

ACCRUED VACATION

The Company accrues vacation pay by establishing a liability for vacation earned during the current year, but not payable until the following year. The accrued vacation totaled $14.4 million, $14.4 million and $13.4 million at December 31, 2000, 1999 and 1998, 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

Certain amounts have been reclassified on the consolidated financial statements to conform to the 2000 presentation.

2. Income Taxes

The items comprising tax expense are as follows:

Year ended December 31 (dollars in thousands)	2000	1999	1998
Provision For Current Income Taxes:			
Federal	$ 23,311	$ 50,090	$ 72,084
State	6,824	8,617	12,638
Total Provision For Current Income Taxes	30,135	58,707	84,722
Provisions (Benefit) For Deferred Income Taxes, net:			
Federal			
Depreciation	51,398	29,392	1,490
Repair allowance	1,711	1,978	1,200
Removal costs	2,710	3,461	(220)
Salvage	(1,718)	(3,131)	---
Software development costs	(3,162)	2,906	---
Casualty losses	(5,439)	5,167	---
Contributions in aid of construction	(2,689)	(1,249)	(442)
Company restructuring	46	100	22
Pension expense	1,325	(2,626)	14,806
Bond redemption-unamortized costs	(1,064)	249	8,458
Partnerships	4,682	4,270	1,400
Other	(2,685)	(6,134)	(938)
State	7,032	1,858	3,296
Total Provision (Benefit) For Deferred Income Taxes, net	52,147	36,241	29,072
Deferred Investment Tax Credits, net	(5,150)	(5,150)	(5,150)
Income Taxes Relating to Other Income and Deductions	(627)	146	---
Total Income Tax Expense	$ 76,505	$ 89,944	$ 108,644
Pretax Income	$ 223,540	$ 241,203	$ 274,516

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

Year ended December 31	2000	1999	1998
Statutory federal tax rate	35.0%	35.0%	35.0%
State income taxes, net of federal income tax benefit	4.0	2.8	3.8
Tax credits, net	(3.4)	(3.4)	(3.0)
Other, net	(1.4)	2.9	3.8
Effective income tax rate as reported	34.2%	37.3%	39.6%

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, 2000, 1999 and 1998 are as follows:

(dollars in thousands)	2000	1999	1998
Current Deferred Tax Assets:			
Accrued vacation	$ 5,184	$ 5,497	$ 5,088
Uncollectible accounts	4,089	1,776	1,242
Capitalization of indirect costs	318	249	172
RAR interest	774	774	774
Provision for Worker's Compensation claims	272	348	462
Other	32	85	73
Current Deferred Tax Assets	$ 10,669	$ 8,729	$ 7,811
Deferred Tax Liabilities:			
Accelerated depreciation and other property-related differences	$ 587,038	$ 532,814	$ 491,943
Allowance for funds used during construction	34,093	37,152	38,575
Income taxes recoverable through future rates	32,365	36,335	40,310
Bond redemption-unamortized costs	8,964	9,640	9,353
Total	662,460	615,941	580,181
Deferred Tax Assets:			
Deferred investment tax credits	(18,388)	(20,130)	(21,875)
Income taxes refundable through future rates	(17,404)	(20,974)	(24,547)
Postemployment medical and life insurance benefits	(1,792)	(1,795)	(3,100)
Company pension plan	(4,078)	(5,206)	(682)
Other	(2,438)	(1,699)	1,963
Total	(44,100)	(49,804)	(48,241)

Accumulated Deferred Income Tax Liabilities	$ 618,360	$ 566,137	$ 531,940

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 58,627, 65,831 and 25,705 shares of new stock issued pursuant to the Stock Incentive Plan during 2000, 1999 and 1998, respectively. The $1.5 million increase in 2000 in premium on capital stock as presented on the Consolidated Statements of Capitalization, represents the issuance of common stock pursuant to the Stock Incentive Plan. The $71.7 million decrease in 1999 in premium on capital stock represents the repurchase of common stock, which was only partially offset by the issuance of common stock pursuant to the Stock Incentive Plan.

There were 6,324,118 shares of unissued common stock reserved for the various employee and Company stock plans at December 31, 2000. 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. In October 2000, the Shareowners Rights Plan was amended and restated to extend the expiration date to December 11, 2010 and to change the exercise price of the rights.

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 58,627, 65,831 and 38,900 shares of common stock during 2000, 1999 and 1998, respectively. The Company also reacquired 13,195 shares in 1998. The restricted stock distributed vests at the end of three years.

Changes in common stock were:

(dollars in thousands)	2000	1999	1998
Shares outstanding January 1	77,863	80,798	80,772
Repurchased shares	---	(3,000)	---
Issued/reacquired under the Stock Incentive and Restricted Stock Plan, net	59	65	26
Shares outstanding December 31	77,922	77,863	80,798

STOCK OPTIONS

In January 2000, the Company awarded approximately 364,200 stock options, with an exercise price of $18.25. During 2000, 36,068 stock options were forfeited and 8,332 stock options expired. In January 1999, the Company awarded approximately 442,800 stock options, with an exercise price of $28.75. In January 1998, approximately 427,600 stock options were awarded with an exercise price of $25.9375. Options granted under the Stock Incentive Plan 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, 2000, 1,190,200 stock options were outstanding.

During 1996, the Company adopted SFAS No. 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 Accounting Principles Board ("APB") Opinion No. 25, "Accounting for Stock Issued to Employees". Accordingly, the Company has not recognized compensation expense for its stock-based awards to employees. Using the Black-Scholes pricing model, the estimated fair value of each option granted was $3.34 in 2000.

The following table shows assumptions used to estimate the fair value of options granted in 2000:

Expected life of options	7 years
Risk-free interest rate	5.08%
Expected volatility	22.16%
Expected dividend yield	5.71%

The following table reflects pro forma earnings available for common stock had the Company elected to adopt the fair value approach to SFAS No. 123:

(dollars in thousands)	2000	1999	1998
Earnings available for			

common stock:	As Reported........	$147,035	$151,259	$165,139
	Pro Forma..........	146,438	150,864	164,933

In 2000, reported earnings per share was $1.89, while the pro forma earnings per share had the Company elected to adopt the fair value approach to SFAS 123 was $1.88. Reported and pro forma earnings per share amounts are equivalent for 1998 and 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 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 October 15, 2000, a $110 million series of OG&E's 6.25 percent Senior Notes matured. The Company temporarily funded this debt through short-term borrowings. On October 23, 2000, OG&E issued $110 million of 7.125 percent Senior Notes, Series due October 15, 2005. Net proceeds from this transaction were used to repay the temporary short-term borrowings from the Company.

Enogex retired $57 million of long-term debt that matured in the third quarter of 2000. This debt consisted of $23 million principal amount of 6.77 percent medium-term notes due August 7, 2000, $4 million principal amount of 6.76 percent medium-term notes due August 7, 2000, $20 million principal amount of 6.68 percent medium-term notes due August 31, 2000 and $10 million principal amount of 6.70 percent medium-term notes due September 1, 2000.

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 one year interest rate swap agreements to manage interest costs associated with this $400 million issue. The effect of these swap agreements reduced the overall effective interest rate from 8.125 percent to 6.6875 percent during 2000. The interest rate swaps expired in January 2001. The balance of the proceeds from this new debt was used for general corporate purposes. The following table itemizes the Enogex long-term debt assumed as part of the Transok acquisition:

(dollars in thousands)	
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

On January 10, 2001, Enogex retired $5 million principal amount of 7.75 percent medium-term notes due April 24, 2023. This debt had been assumed as part of the Transok acquisition.

As of December 31, 2000, other Enogex long-term debt consisted of $400 million principal amount of 8.125 percent Senior Notes due January 15, 2010, $75 million principal amount of 7.15 percent Senior Notes subject to semiannual principal payments of $1 million each and due June 1, 2018, $6.9 million principal amount of 7.00 percent Notes due July 1, 2020 and $93 million of medium-term notes at a composite rate of 6.96 percent. The following table itemizes the other Enogex long-term debt:

December 31 (dollars in thousands)	2000	1999	1998
Series Due August 7, 2000 -- 6.76% - 6.77%.......	$ ---	$ 27,000	$ 27,000
Series Due August 31, 2000 -- 6.68%..............	---	20,000	20,000
Series Due September 1, 2000 - 6.70%.............	---	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 January 15, 2010 -- 8.125%............	400,000	---	---
Series Due June 1, 2018 -- 7.15%.................	75,000	77,000	79,000
Series Due July 1, 2020 -- 7.00%.................	6,941	6,486	5,671
Total..	$ 574,941	$ 233,486	$ 234,671

Maturities of the Company's long-term debt during the next five years consist of $2 million in 2001; $115 million in 2002; $14.3 million in 2003; $57.8 million in 2004, and $152.9 million in 2005.

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 2000 (excluding the temporary short-term financing for the Transok acquisition) were $284.5 million and $182.4 million, respectively, at a weighted average interest rate of 6.68%. The weighted average interest rates for 1999 and 1998 were 5.36% and 5.75%, respectively. Short-term debt in the amount of $284.5 million was outstanding at December 31, 2000. The Company has the necessary regulatory approvals to incur up to $400 million in short-term borrowings at any one time. At December 31, 2000, the Company had in place a line of credit for up to $300 million, $200 million of which was to expire on January 15, 2001, and the remaining $100 million was to expire on January 15, 2004. In January 2001, the Company's line of credit for up to $200 million was renewed, with an expiration date of January 15, 2002.

8. Pension and Postretirement Benefit Plans

All eligible employees of the Company are covered by a non-contributory defined benefit pension plan. In early 2000, the Board approved significant changes to the pension plan. Under the existing plan, benefits were based primarily on years of service and the average of the five highest consecutive years of compensation during an employee's last ten years prior to retirement, with reductions in benefits for each year prior to age 62 that an employee retired and additional significant reductions for retirement prior to age 55. The changes to the existing pension plan included: (i) elimination of the significant reduction for employees electing to retire before age 55, (ii) the addition of an alternative method of computing the reduction in benefits for an employee retiring prior to age 62, which alternative method is based on years of service and age with an employee whose age and years of service total or exceed 80 at the time of retirement receiving no reduction in the benefits payable under the plan, and (iii) the ability of an employee at time of retirement to receive, in lieu of an annuity, a lump sum payment equal to the present value of the annuity. Also, for employees hired after January 31, 2000, the pension plan will be a cash balance plan, under which the Company annually will contribute to the employee's account an amount equal to 5 percent of the employee's annual compensation plus accrued interest. Employees hired prior to February 1, 2000, will receive the greater of the cash balance benefit or the benefit based on final average compensation as described above.

It is the Company's policy to fund the plan on a current basis to comply with the minimum required contributions under existing tax regulations. The Company made contributions of $16.2 million during 2000 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"). Under the existing plan, employees retiring from the Company on or after attaining age 55 who have met certain length of service requirements were entitled to these benefits. Pursuant to amendments made to the medical plan in 2000, employees hired prior to February 1, 2000, whose age and years of service total or exceed 80 or have attained age 55 with 10 years of service at the time of retirement are entitled to these benefits. Employees hired after January 31, 2000, are not entitled to the medical 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 follows:

Projected Benefit Obligations:

	Pension Plan			Postretirement Benefit Plans		
(dollars in thousands)	2000	1999	1998	2000	1999	1998
Beginning obligations	$(299,996)	$(342,433)	$(320,842)	$ (83,428)	$ (89,094)	$ (94,199)
Service cost	(10,559)	(8,241)	(8,272)	(2,084)	(2,695)	(2,030)
Interest cost	(27,516)	(21,363)	(21,766)	(7,200)	(6,003)	(5,748)
Participant contributions	---	---	---	(1,093)	(1,143)	(1,077)
Plan changes	(20,528)	---	(3,561)	(17,373)	(1,500)	---
Actuarial gains (losses)	(77,862)	53,535	(8,568)	(379)	7,950	6,029
Benefits paid	40,460	17,695	20,345	9,170	9,057	7,931
Expenses	766	811	231	---	---	---
Ending obligations	$(395,235)	$(299,996)	$(342,433)	$(102,387)	$ (83,428)	$ (89,094)

Fair Value of Plans' Assets:

	Pension Plan			Postretirement Benefit Plans		
(dollars in thousands)	2000	1999	1998	2000	1999	1998
Beginning fair value	$ 311,937	$ 304,169	$ 242,254	$ 55,509	$ 52,264	$ 45,619
Actual return on plans' assets	9,597	22,517	30,865	42	3,245	5,133
Employer contributions	16,190	3,757	51,626	6,184	6,307	5,474
Participants' contributions	---	---	---	943	980	915
Benefits paid	(40,460)	(17,695)	(20,345)	(7,127)	(7,287)	(6,388)
Expenses	(764)	(811)	(231)	---	---	---
Other	---	---	---	---	---	1,511
Ending fair value	$ 296,500	$ 311,937	$ 304,169	$ 55,551	$ 55,509	$ 52,264

Funded Status of Plans:

	Pension Plan			Postretirement Benefit Plans		
(dollars in thousands)	2000	1999	1998	2000	1999	1998
Funded status of the plans	$ (98,735)	$ 11,941	$ (38,264)	$ (46,836)	$ (27,919)	$ (36,831)
Unrecognized net (gain) loss	47,435	(47,326)	1,435	(17,428)	(24,337)	(18,713)
Unrecognized prior service cost	53,197	37,289	40,448	17,333	1,396	---
Unrecognized transition obligation	(1,265)	(2,527)	(3,790)	32,988	35,738	38,487
Net balance sheet asset (liability)	$ 632	$ (623)	$ (171)	$ (13,943)	$ (15,122)	$ (17,057)

Net Periodic Benefit Cost:

Postretirement

(dollars in thousands)	Pension Plan 2000	Pension Plan 1999	Pension Plan 1998	Benefit Plans 2000	Benefit Plans 1999	Benefit Plans 1998
Service cost	$ 10,559	$ 8,241	$ 8,272	$ 2,084	$ 2,695	$ 2,030
Interest cost	27,516	21,363	21,766	7,200	6,003	5,748
Return on plan assets	(24,160)	(27,374)	(21,443)	(4,985)	(3,963)	(4,309)
Amortization of transition obligation	(1,263)	(1,263)	(1,263)	2,749	2,749	2,749
Amortization of net gain	(91)	---	---	(1,727)	(1,244)	(2,105)
Net amount capitalized or deferred	(2,245)	(880)	---	---	(1,087)	(613)
Net amortization and deferral	---	(29)	---	---	---	---
Amortization of unrecognized prior service cost	4,619	3,159	3,159	1,436	104	---
Net periodic benefit costs	$ 14,935	$ 3,217	$ 10,491	$ 6,757	$ 5,257	$ 3,500

Rate Assumptions:

	Pension Plan 2000	Pension Plan 1999	Pension Plan 1998	Postretirement Benefit Plans 2000	Postretirement Benefit Plans 1999	Postretirement Benefit Plans 1998
Discount rate	8.00%	8.00%	6.75%	8.00%	8.00%	6.75%
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%	7.00%	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 $1.1 million, $1.0 million and $0.9 million at December 31, 2000, 1999 and 1998, 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, $0.9 million and $0.7 million at December 31, 2000, 1999 and 1998, respectively.

The effects of a one-percentage point increase on the aggregate of accumulated postretirement benefit obligation for health care benefits would be approximately $11.3 million, $7.1 million and $8.2 million at December 31, 2000, 1999 and 1998, 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 $9.4 million, $6.0 million and $6.9 million at December 31, 2000, 1999 and 1998, 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)	2000	1999	1998
Operating Information:			
Operating Revenues			
Electric utility	$1,453,585	$1,286,844	$1,312,078
Non-utility	2,111,600	1,086,105	506,471
Intersegment revenues (A)	(266,458)	(200,515)	(200,812)
Total	$3,298,727	$2,172,434	$1,617,737
Pre-tax Operating Income			
Electric utility	$ 271,138	$ 269,564	$ 315,798
Non-utility	78,683	68,601	23,659
Total	$ 349,821	$ 338,165	$ 339,457
Income Tax Expense (Benefit)			
Electric utility	$ 80,342	$ 84,965	$ 105,574
Non-utility	(3,837)	4,979	3,070
Total	$ 76,505	$ 89,944	$ 108,644
Interest Income			
Electric utility	$ 1,121	$ 1,710	$ 2,314
Non-utility	24,907	9,928	7,046
Intersegment (B)	(22,240)	(8,801)	(5,799)
Total	$ 3,788	$ 2,837	$ 3,561

Interest Expense			
Electric utility	$ 49,009	$ 46,658	$ 49,941
Non-utility	108,124	63,142	27,628
Intersegment (B)	(22,240)	(8,801)	(5,799)
Total	$ 134,893	$ 100,999	$ 71,770
Net Income			
Electric utility	$ 142,392	$ 139,041	$ 160,338
Non-utility	4,643	12,218	5,534
Total	$ 147,035	$ 151,259	$ 165,872
Investment Information:			
Identifiable Assets as of December 31			
Electric utility	$2,437,449	$2,320,660	$2,320,097
Non-utility	1,882,181	1,600,674	663,832
Total	$4,319,630	$3,921,334	$2,983,929
Other Information:			
Depreciation and amortization			
Electric utility	$ 117,257	$ 119,059	$ 116,213
Non-utility	58,887	45,982	33,605
Total	$ 176,144	$ 165,041	$ 149,818
Construction Expenditures			
Electric utility	$ 128,410	$ 101,263	$ 96,678
Non-utility	51,061	79,900	138,553
Total	$ 179,471	$ 181,163	$ 235,231

(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 2001 are estimated at $164 million.

OG&E acquires some of its natural gas for boiler fuel under a wellhead contract that contains provisions allowing the owner to require prepayments for gas if certain minimum quantities are not taken. At December 31, 2000, 1999 and 1998, outstanding prepayments for gas, including the amounts classified as current assets, under this and other prior similar contracts were approximately $15.0 million, $14.9 million and $15.2 million, respectively.

At December 31, 2000, OG&E held non-cancelable operating leases covering 1,481 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)

2001	$5,541	2004	$ 5,203
2002	5,429	2005	5,091
2003	5,316	2006 and beyond	44,710
Total Minimum Lease Payments			$ 71,290

Rental payments under operating leases were approximately $5.4 million in 2000, $4.9 million in 1999 and $5.3 million in 1998. OG&E is currently in the process of replacing these leases. Management does not anticipate the terms of the new leases to differ significantly from the existing leases.

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

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 2000, 1999 and 1998, OG&E made total payments to cogenerators of approximately $227.6 million, $229.3 million and $226.5 million, of which $189.6 million, $188.8 million and $185.5 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: 2001 - $191 million, 2002 - $192 million, 2003 - $163 million, 2004 - $151 million and 2005 - $88 million.

Approximately $2.5 million of the Company's construction expenditures budgeted for 2001 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 $50.5 million during 2001, compared to approximately $47.1 million in 2000. 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

Beginning in 2000, OG&E became subject to more stringent sulfur dioxide emissions. These lower limits had no significant financial impact due to OG&E's earlier decision to burn low sulfur coal. In 2000, OG&E's sulfur dioxide emissions were well below the allowable limits. With respect to nitrogen oxides, OG&E continues to meet the current emission standard. However, further reductions in nitrogen oxides could be required if, among other things, a study currently being conducted by the state of Oklahoma determines that such nitrogen oxides are contributing to regional haze, the United States Supreme Court decides to uphold new ozone standards or if OG&E fails to meet the new fine particulate standards. Any of these scenarios would require significant capital expenditures and increased operating and maintenance costs.

In 1997, the United States was a signatory to the Kyoto Protocol on global warming. While the Protocol is not likely to be ratified by the U.S. Senate, some form of legislation limiting carbon dioxide emissions may occur. If legislation is passed, it 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.

The Oklahoma Department of Environmental Quality's Clean Air Act Amendment Title V permitting program was approved by the Environmental Protection Agency ("EPA") in March 1996. By March of 1997, OG&E had submitted all required permit applications. As of December 31, 2000, OG&E had received Title V permits for all but three of its generating stations. Since OG&E submitted all its permit applications on time it is considered in compliance with the Title V permit program even though all permits have not been issued. Air permit fees for generating stations were approximately $0.4 million in 2000 and are estimated to be about the same in 2001.

On December 14, 2000, the EPA announced its decision to regulate mercury emissions from coal-fired utility boilers. Limits on the amount of mercury emitted are expected to be finalized by December 2004, although full compliance by the Company is not expected to be required until 2008. Depending upon the final regulations implemented, this could result in significant capital and operating expenditures.

Section 316(b) of the Clean Water Act requires that the location, design, construction and capacity of any cooling water intake structure reflect the "best available technology" for minimizing environmental impacts. The EPA's original rules on this issue were set-aside in 1977 by the Fourth Circuit U.S. Court of Appeals. In 1993, EPA announced its plan to develop new rules in part due to a lawsuit filed by the Hudson Riverkeeper. To settle the lawsuit, the EPA signed a court-approved consent decree to develop 316(b) regulations on an agreed upon schedule. Proposed rules, for existing utility sources, are expected to be published in February 2002 and final rules are expected to be promulgated in August 2003. Based on the content of the final rules, capital and operating expenses may increase at most of OG&E's generating facilities. Increased capital costs may be necessary to retrofit and/or redesign existing intake structures to comply with any new 316(b) regulations.

OG&E is a party to an action brought by the EPA concerning cleanup of a disposal site. OG&E was not the owner or operator of this site, rather OG&E, along with many others, shipped materials to the owner or operator of the site who disposed of the materials. OG&E's total waste disposed at this site is minimal and on February 15, 1996, OG&E elected to participate in the de minimis settlement offered by the 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.

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 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 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 appealed the trial court's ruling and oral arguments were heard by the Tenth Circuit Court of Appeals in January 2001. A decision is not expected for several months. While the outcome of the 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

On January 12, 2000, the OCC Staff (the "Staff") filed three applications to address various aspects of OG&E's electric rates. The first application related to the completion on March 1, 2000, of the recovery of the amortization premium paid by OG&E when it acquired Enogex in 1986 and the resulting removal, pursuant to the APC Rider, of $12.8 million ($10.7 million in the Oklahoma Jurisdiction) from the amount being recovered by OG&E from its customers through currently authorized electric rates. OG&E consented to this action and in March 2000, the OCC approved the APC Rider for $10.7 million annually.

The second application related to a review of the GEP Rider, which, as part of the OCC's order issued in 1997 in connection with OG&E's last general rate review (the "1997 Order"), was scheduled for review in March 2000. OG&E collected approximately $9.9 million pursuant to the GEP Rider during 2000. The GEP Rider initially was designed so that when OG&E's average annual cost of fuel per kwh was 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 was allowed to collect, through the GEP Rider, one-third of the amount by which OG&E's average annual cost of fuel was below 96.261 percent of the average of the other specified utilities. If OG&E's fuel cost exceeded 103.739 percent of the stated average, OG&E was not allowed to recover one-third of the fuel costs above that average from Oklahoma customers. In April 2000 testimony, the Staff stated that they continued to support incentive programs that reward superior performance, but in their view the existing GEP Rider was not functioning as they had originally envisioned it.

In June 2000, the OCC approved the collection of $6.6 million through the GEP Rider for the time period July 1, 2000 through June 30, 2001 and approved the following four modifications to the GEP Rider: (i) changing OG&E's peer group to include utilities with a higher coal-to-gas generation mix; (ii) reducing the amount of fuel costs that can be recovered if OG&E's costs exceed the new peer group by changing the percentage above which OG&E will not be allowed to recover one-third of the fuel costs from Oklahoma customers from 103.739 percent to 101.0 percent; (iii) reducing OG&E's share of cost savings as compared to its new peer group from 33 percent to 30 percent; and (iv) limiting to $10.0 million the amount of any awards paid to OG&E or penalties charged to OG&E. The GEP Rider is to be revised effective July 1 of each year to reflect changes in the relative annual cost of fuel reported for the preceding calendar year.

The final application, relating to fuel cost recoveries, was used by the Staff to address the competitive bid process of OG&E's gas transportation needs. In the 1997 Order, the OCC approved a stipulation wherein OG&E agreed to initiate a competitive bidding process for gas transportation service to its gas-fired plants, with the competitive services commencing 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 removal of the APC Rider, upon the completion of the recovery from customers of the amortization premium paid by OG&E when it acquired Enogex in 1986) and remain at that level until competitively-bid gas transportation began. 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 OG&E's 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 executed a gas transportation contract with Enogex under which Enogex continues to serve 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 customers. OG&E negotiated with the Staff, the Office of the Oklahoma Attorney General and a coalition of industrial customers 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.

In July 2000, OG&E entered into a stipulation (the "Stipulation") with the Staff, the Office of the Attorney General and a coalition of industrial customers regarding the competitive bid process of OG&E's gas transportation service. The Stipulation (which, with one exception, was signed by all parties to the proceeding) would permit OG&E to recover $25.2 million annually for gas transportation services to be provided by Enogex pursuant to the competitive bid process. The Stipulation was presented for approval to an Administrative Law Judge ("ALJ") in September 2000, and the ALJ recommended its approval. However, at a hearing on September 28, 2000, the OCC chose to delay the decision concerning the Stipulation and two of the three commissioners expressed concern over the competitive bid process. OG&E cannot predict what further action the OCC may take. OG&E believes that the competitive bid process was appropriate and is currently collecting $28.5 million on an annual basis through its base rates and APC Rider for gas transportation services from Enogex for the power plant requirements covered by the competitive bid.

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.

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:

	2000		1999		1998	
(dollars in thousands)	Carrying Amount	Fair Value	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-Term Debt and Preferred Securities:						
Senior Notes...........................	$567,182	$552,256	$457,646	$422,181	$567,512	$593,313
Industrial Authority Bonds.............	135,400	135,400	135,400	135,400	135,400	135,400
Enogex Inc. Notes......................	745,941	797,766	347,486	410,578	232,671	251,505
Trust Originated Preferred Securities...	200,000	200,000	200,000	200,000	---	---

13. Subsequent Events

In January 2001, the Company renewed its agreement for a line of credit for up to $300 million, $200 million of which is to expire on January 15, 2002, and $100 million of which is to expire on January 15, 2004.

On January 10, 2001, Enogex retired $5 million principal amount of 7.75 percent medium-term notes due April 24, 2023. This debt was assumed as part of the Transok acquisition.

Report of Independent Public Accountants

ARTHUR ANDERSEN

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, 2000, 1999 and 1998, 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, 2000, 1999 and 1998, 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 18, 2001

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, 2000, 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
Steven E. Moore, Chairman of the Board,
President and Chief Executive Officer

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

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

/s/ Donald R. Rowlett
Donald R. Rowlett, Vice President
and Controller

Supplementary Data

Interim Consolidated Financial Information (Unaudited)

In the opinion of the Company, the following quarterly information includes all adjustments, consisting of normal recurring adjustments, necessary for a fair statement of the 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............................	2000	$ 982,276	$1,007,966	$ 726,904	$ 581,581
	1999	575,978	767,390	450,861	378,205
	1998	361,750	555,999	412,621	287,367

Operating income	2000	$ 40,819	$ 205,060	$ 71,746	$ 32,196
	1999	50,570	180,373	73,147	34,075
	1998	31,803	202,943	92,789	11,922
Net income (loss)	2000	$ 7,208	$ 107,307	$ 31,744	$ 776
	1999	12,179	90,204	37,744	11,132
	1998	10,230	108,117	47,865	(340)
Earnings (loss) available for common stock	2000	$ 7,208	$ 107,307	$ 31,744	$ 776
	1999	12,179	90,204	37,744	11,132
	1998	10,230	108,117	47,865	(1,073)
Earnings (loss) per average common share	2000	$ 0.09	$ 1.38	$ 0.41	$ 0.01
	1999	0.15	1.16	0.49	0.14
	1998	0.13	1.33	0.59	(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 30, 2001. 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:

- Consolidated Balance Sheets at December 31, 2000, 1999 and 1998
- Consolidated Statements of Income for the years ended December 31, 2000, 1999 and 1998
- Consolidated Statements of Retained Earnings for the years ended December 31, 2000, 1999 and 1998
- Consolidated Statements of Capitalization at December 31, 2000, 1999 and 1998
- Consolidated Statements of Cash Flows for the years ended December 31, 2000, 1999 and 1998
- Notes to Consolidated Financial Statements
- Report of Independent Public Accountants
- Report of Management

Supplementary Data

- Interim Consolidated Financial Information

2. Financial Statement Schedule (included in Part IV)	Page
Schedule II - Valuation and Qualifying Accounts	81
Report of Independent Public Accountants	82

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)
4.05	Supplemental Indenture No. 4, dated as of October 15, 2000, being a supplement instrument to Exhibit 4.01 hereto. (Filed as Exhibit 4.02 to OG&E's Form 8-K filed on October 20, 2000 (File No. 1-1097) and incorporated by reference herein)
10.01	Coal Supply Agreement dated March 1, 1973, between OG&E and Atlantic Richfield Company. (Filed as Exhibit 5.19 to Registration Statement No. 2-59887 and incorporated by reference herein)
10.02	Amendment dated April 1, 1976, to Coal Supply Agreement dated March 1, 1973, between OG&E and Atlantic Richfield Company, together with related correspondence. (Filed as Exhibit 5.21 to Registration Statement No. 2-59887 and incorporated by reference herein)
10.03	Second Amendment dated March 1, 1978, to Coal Supply Agreement dated March 1, 1973, between OG&E and Atlantic Richfield Company. (Filed as Exhibit 5.28 to Registration Statement No. 2-62208 and incorporated by reference herein)
10.04	Amendment dated June 27, 1990, between OG&E and Thunder Basin Coal Company, to Coal Supply Agreement dated March 1, 1973, between OG&E and Atlantic Richfield Company. (Filed as Exhibit 10.04 to OG&E's Form 10-K 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. (Filed as Exhibit 10.06 to OGE Energy's Form 10-K for the year ended December 31, 1999 (File No. 1-12579) and incorporated by reference herein)

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 Energy Corp.'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)

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

10.13 Amendment No. 3 to OG&E's Restoration of Retirement Income Plan.

10.14 Amendment No. 4 to OGE Energy's Restoration of Retirement Income Plan.

21.01 Subsidiaries of the Registrant.

23.01 Consent of Arthur Andersen LLP.

24.01 Power of Attorney.

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)

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10.13 Amendment No. 3 to OG&E's Restoration of Retirement Income Plan.

10.14 Amendment No. 4 to OGE Energy's Restoration of Retirement Income Plan.

(b) Reports on Form 8-K

Item 5. Other Events, dated October 20, 2000.

OGE ENERGY CORP.

SCHEDULE II - Valuation and Qualifying Accounts

Column A	Column B	Column C		Column D	Column E
Description	Balance Beginning of Year	Charged to Costs and Expenses	Charged to Other Accounts	Deductions	Balance End of Year
2000			(Thousands)		
Reserve for Uncollectible Accounts	$ 5,270	$7,262	-	$ 8,397	$ 4,135
1999					
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

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 18, 2001. Our audits were made for the purpose of forming an opinion on those statements taken as a whole. The schedule listed on Page 77 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 18, 2001

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 26th day of March, 2001.

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 26, 2001
/ s / James R. Hatfield James R. Hatfield	Principal Financial Officer; and	March 26, 2001
/ s / Donald R. Rowlett Donald R. Rowlett	Principal Accounting Officer.	March 26, 2001
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;	
Ronald H. White, M.D.	Director; and	
J. D. Williams	Director.	
/ s / Steven E. Moore By Steven E. Moore (attorney-in-fact)		March 26, 2001

Exhibit Index

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23.01 Consent of Arthur Andersen LLP.

24.01 Power of Attorney.

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

Exhibit 10.13

AMENDMENT NO. 3
TO THE
OKLAHOMA GAS AND ELECTRIC COMPANY
RESTORATION OF RETIREMENT INCOME PLAN
(As Amended and Restated Effective January 1, 1994)

Oklahoma Gas Electric Company, an Oklahoma corporation, in accordance with the authority contained in Section 9 of the Oklahoma Gas and Electric Company Restoration of Retirement Income Plan (the "Plan"), hereby amends the Plan, effective as of January 1, 1998, as follows:

1. The second paragraph of Section 5 of the Plan is deleted and replaced with the following paragraph:

“Inmaking this computation, it is intended that the recipient should receive an amount from this Plan which, if expressed as an actuarial equivalent lump-sum amount, would enable him to purchase an individual annuity that would produce a monthly benefit, after payment of applicable Federal, State and local income taxes on such lump-sum amount at the maximum rates in effect in the year of commencement of Plan benefits, equal to the monthly benefit, after payment of such income taxes, that the recipient would have received under the Retirement Plan had Sections 401(a)(17) and 415 of the Code not been applicable thereto, less the benefits which are payable under the Retirement Plan.”

2. The first paragraph of Section 6 of the Plan is deleted and replaced with the following paragraph:

“Payment of benefits under this Plan shall be made only when, and if, the participant is entitled to benefits under the Retirement Plan. Such payments shall commence on the participant’s actual retirement date or within a reasonable time thereafter, and such payments shall be made, on an actuarial equivalent basis, in monthly or annual installments over a specified number of years to be determined by the Retirement Committee in its discretion. If a participant dies before the expiration of the specified payment period, his or her beneficiary or beneficiaries shall be paid a lump-sum amount equal to the present value of the remaining installment payments, determined on an actuarial equivalent basis.”

AMENDMENT NO. 4
TO THE
OKLAHOMA GAS AND ELECTRIC COMPANY
RESTORATION OF RETIREMENT INCOME PLAN
(As Amended and Restated Effective January 1, 1994)

OGE Energy Corp., an Oklahoma corporation (the "Company"), in accordance with the authority reserved to the Company under Section 9 of the OGE Energy Corp. Restoration of Retirement Income Plan (the "Plan"), hereby amends the Plan, effective as of January 1, 2000, in the following particulars:

1. By deleting the first paragraph of Section 2 of the Plan and substituting the following new paragraph therefore:

"" Compensation" shall mean, during an applicable period, the participant's Compensation under the Retirement Plan, except that (i) such Compensation shall not be limited by Code Section 401(a)(17) as in effect during such applicable period, (ii) such Compensation shall include amounts, if any, deferred by the participant for the calendar year in question under the OGE Energy Corp. Deferred Compensation Plan (the "Deferred Compensation Plan"), and (iii) Compensation under this Plan shall include bonuses payable pursuant to the OGE Energy Corp. Annual Incentive Plan. Such bonuses shall be included as Compensation for purposes of the Plan in the year in which the services to which the bonuses relate are preformed, notwithstanding the fact that the bonuses are not actually declared and paid to participants until the following year."

2. By deleting Section 4 of the Plan and substituting the following therefore:

4. <u>Eligibility</u>

Participants in the Retirement Plan whose pension or pension-related benefits under the Retirement Plan are limited by (i) the provisions thereof relating to the maximum benefit limitations of Section 415 of the Code (the "415 Limit"), (ii) the limitation on includible Compensation under the Code 401(a)(17), as in effect on and after January 1, 1989, and as adjusted and/or amended from time to time (the "401(a)(17) Limit"), or (iii) by reason of deferrals under the Deferred Compensation Plan shall be eligible for benefits under this Plan. In no event shall a participant who is not entitled to benefits under the Retirement Plan be eligible for a benefit under this Plan."

3. By deleting the second paragraph of subsection 5(b) of the Plan and substituting the following therefore:

"In making this computation, it is intended that the recipient should receive an amount from this Plan which, if expressed as an actuarial equivalent lump-sum amount, would enable him to purchase an individual annuity that would produce a monthly benefit, after payment of applicable Federal, State and local income taxes on such lump-sum amount at the maximum rates in effect in the year of commencement of Plan benefits, equal to the monthly benefit, after payment of such income taxes, that the recipient would have received under the Retirement Plan had Sections 401 (a)(17) and 415 of the Code not been applicable thereto and if the participant's deferrals under the Deferred Compensation Plan were treated as compensation under the Retirement Plan, less the benefits which are payable under the Retirement Plan."

4. By deleting the first sentence of the third paragraph of subsection 5(b) of the Plan and substituting the following therefore:

"Benefits payable under this Plan shall be computed in accordance with the foregoing and with the objective that such recipient should receive under this Plan and the Retirement Plan that total amount which would have been payable to that recipient solely under the Retirement Plan had the 415 and the 401(a)(17) Limit not been applicable thereto and the participant's deferrals under the Deferred Compensation Plan were treated as compensation under the Retirement Plan."

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 Holding LLC	Delaware	100.0
OGE Energy Capital Trust I	Oklahoma	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 18, 2001 included in the OGE Energy Corp. Form 10-K for the year ended December 31, 2000, 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 23, 2001

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, 2000; 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 17th day of January 2001.

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 17th day of January, 2001.

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

My Commission Expires:
May 3, 2003

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, 2000; and

WHEREAS, each of the undersigned holds the office in the Company herein-below set opposite his name;

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 attorney with full power to act for him and in his 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 has hereunto set his hand this 21st day of March 2001.

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J. D. Williams, Director                        / s / J. D. Williams
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STATE OF OKLAHOMA  )
                   )  SS
COUNTY OF OKLAHOMA )
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On the date indicated above, before me, Debbie Peters, Notary Public in and for said County and State, personally appeared the above named director of OGE ENERGY CORP., an Oklahoma corporation, and known to me to be the person whose name is subscribed to the foregoing instrument, and he acknowledged to me that he executed the same as his own free act and deed.

IN WITNESS WHEREOF, I have hereunto set my hand and affixed my official seal on the 21st day of March, 2001.

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

My Commission Expires:
May 3, 2003

Exhibit 99.01

OGE Energy Corp. Cautionary Factors

The Private Securities Litigation Reform Act of 1995 provides a "safe harbor" for forward-looking statements to encourage such disclosures without the threat of litigation providing those statements are identified as forward-looking and are accompanied by meaningful, cautionary statements identifying important factors that could cause the actual results to differ materially from those projected in the statement. Forward-looking statements have been and will be made in written documents and oral presentations of OGE Energy Corp. (the "Company"). Such statements are based on management's beliefs as well as assumptions made by and information currently available to management. When used in the Company's documents or oral presentations, the words "anticipate", "estimate", "expect", "objective" and similar expressions are intended to identify forward-looking statements. In addition to any assumptions and other factors referred to specifically in connection with such forward-looking statements, factors that could cause the Company's actual results to differ materially from those contemplated in any forward-looking statements include, among others, the following:

- Increased competition in the utility industry, including effects of: decreasing margins as a result of competitive pressures; industry restructuring initiatives, including state legislation providing for retail customer choice of electricity providers; 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, 2000, 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.