SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

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

OR

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

For the fiscal year ended December 31, 1994   Commission File Number 1-1097

OKLAHOMA GAS AND ELECTRIC COMPANY
(Exact name of registrant as specified in its charter)

Oklahoma (State or other jurisdiction of incorporation or organization)	73-0382390 (I.R.S. Employer Identification No.)
101 North Robinson P.O. Box 321 Oklahoma City, Oklahoma (Address of principal executive offices)	73101-0321 (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
Common Stock	Pacific Stock Exchange
Preferred Stock 4% Cumulative	New York Stock Exchange
First Mortgage Bonds, Series due 1995	New York 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. [ ]

As of February 28, 1995, Common Shares outstanding were 40,354,387. Based upon the closing price on the New York Stock Exchange on February 28, 1995, the aggregate market value of the voting stock held by nonaffiliates of the Company was: Common Stock $1,421,022,063 and 4% Cumulative Preferred Stock $4,976,724.

The proxy statement for the 1995 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

Oklahoma Gas and Electric Company ("OG&E") is a regulated public utility engaged in the generation, transmission and distribution of electricity to retail and wholesale customers. Enogex Inc., a wholly-owned subsidiary of OG&E, and Enogex Inc.'s subsidiaries (collectively, "Enogex") are engaged in non-utility businesses, consisting of diverse natural gas activities. OG&E and Enogex are herein referred to collectively as the "Company." Financial information on the Company's two segments of business is included in Note 8 of Notes to Consolidated Financial Statements.

OG&E, incorporated in 1902 under the laws of the Oklahoma Territory, is the largest electric utility in the State of Oklahoma. OG&E sold its retail gas business in 1928, and now owns and operates an interconnected electric production, transmission and distribution system which includes eight active generating stations with a total capability of 5,637,300 kilowatts. Enogex owns and operates over 3,000 miles of natural gas transmission and gathering pipelines, has interests in four gas processing plants, markets natural gas and natural gas products and invests in the exploration and production of natural gas. At the end of 1994, Enogex had 314 members and OG&E had 2,494 members. OG&E's executive offices are located at 101 North Robinson, P.O. Box 321, Oklahoma City, Oklahoma 73101-0321; telephone (405) 553-3000.

On February 25, 1994, the Oklahoma Corporation Commission ("OCC") issued an order that, among other things, effectively lowered OG&E's rates to its Oklahoma retail customers by approximately $17 million annually and required OG&E to refund approximately $41.3 million. Of the $41.3 million refund, $39.1 million was associated with revenues prior to January 1, 1994, while the remaining $2.2 million related to 1994. See "Regulation and Rates - Recent Regulatory Matters" for a further discussion of this order.

In 1994, the Company restructured and redesigned its operations to reduce costs in order to more favorably position itself for the competitive electric utility environment. As part of this process, the Company implemented a Voluntary Early Retirement Package ("VERP") and a severance package in 1994. These two packages reduced the Company's workforce by approximately 900 employees.

In response to an application filed by OG&E on August 9, 1994, the OCC issued an order on October 26, 1994, that permitted OG&E to: (1) establish a regulatory asset in connection with the costs associated with the workforce reduction; (2) amortize the December 31, 1994, balance of the regulatory asset over 26 months; and (3) reduce OG&E's electric rates by approximately $15 million annually, effective January 1995. In 1995 and 1996, the labor savings are expected to substantially offset the amortization of the regulatory asset and the annual rate reduction of $15 million. See "Regulation and Rates - Recent Regulatory Matters" and Note 10 of Notes to Consolidated Financial Statements for a further discussion of the OCC's orders in February and October 1994.

ELECTRIC OPERATIONS

GENERAL

OG&E furnishes retail electric service in 270 communities and their contiguous rural and suburban areas. During 1994, 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 1.4 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 276 communities served, 247 are located in Oklahoma and 29 in Arkansas.

Approximately 91 percent of total electric operating revenues for the year ended December 31, 1994, 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 5,060 megawatts, and occurred on June 27, 1994. Excluding wheeling, the net on system peak demand was about 4,700 megawatts. However, when firm sales were included, total load responsibility was approximately 4,722 megawatts, resulting in a capacity margin of approximately 22.56 percent. As reflected in the table below and the operating statistics on page 4, kilowatt-hour sales to OG&E customers ("system sales") increased 2.2 percent in 1994 compared to 1993. This increase in system sales was offset by an 82.1 percent decline in sales to other utilities ("off-system sales") which caused total kilowatt-hour sales to be down by 9.0 percent for 1994. However, off-system sales are at much lower prices per kilowatt-hour and have less impact on operating revenues and income than system sales. In 1993 and 1992, factors which resulted in variations in total kilowatt-hour sales included: (i) more normal weather in 1993, (ii) continued customer growth; and (iii) the high level of off-system sales in 1992.

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

	KWH SALES (millions)					
	1994	INC/ (DEC)	1993	Inc/ (Dec)	1992	Inc/ (Dec)
System Sales	20,642	2.2%	20,202	5.0%	19,237	(1.5%)
Off-System Sales	557	(82.1%)	3,104	(25.0%)	4,141	62.1%
Total Sales	21,199	(9.0%)	23,306	(0.3%)	23,378	5.9%

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

Besides competition from other suppliers 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. In October 1992, the National Energy Policy Act of 1992 ("Energy Act") was enacted. Among many other provisions, the Energy Act is designed to promote competition in the development of wholesale power generation in the electric utility industry. Also, numerous states are considering proposals to require "retail wheeling" which is the delivery of power generated by a third party to retail customers. The Energy Act, these proposals and other factors are expected to significantly increase

competition in the electric industry. The Company has taken steps in the past and intends to take appropriate steps in the future to remain a competitive supplier of electricity. See "Regulation and Rates - Recent Regulatory Matters" for a further discussion of this matter.

Electric and magnetic fields ("EMFs") surround all electric tools and appliances, internal home wiring, and external power lines such as those owned by OG&E. During the last several years considerable attention has focused on possible health effects from EMFs. While some recent studies indicate a possible correlation, other similar studies indicate no correlation between

EMFs and health effects. The nation's electric utilities, including OG&E, have participated with the Electric Power Research Institute in the sponsorship of more than $75 million in research to determine the possible health effects of EMFs. Beginning in fiscal year 1994, and in association with the Energy Act, Edison Electric Institute members will help fund $65 million for EMF studies over the next five years. One-half of this amount will be funded by the federal government, and two-thirds of the non-federal funding is expected to be provided by the electric utility industry. Through its participation with the Electric Power Research Institute and Edison Electric Institute, OG&E will continue its support of the research with regard to the possible health effects of EMFs. OG&E is dedicated to delivering electric service in a safe, reliable, environmentally acceptable and economical manner.

OKLAHOMA GAS AND ELECTRIC COMPANY
CERTAIN OPERATING STATISTICS

	Year Ended December 31 1994	1993	1992
ELECTRIC ENERGY:			
(Millions of kWh)			
Generation (exclusive of station use)	18,325	21,789	21,960
Purchased	4,387	3,169	2,724
Total generated and purchased	22,712	24,958	24,684
Company use, free service and losses	(1,513)	(1,652)	(1,306)
Electric energy sold	21,199	23,306	23,378
ELECTRIC ENERGY SOLD:			
(Millions of kWh)			
Residential	6,739	6,631	5,980
Commercial and industrial	10,886	10,595	10,341
Public street and highway lighting	66	64	63
Other sales to public authorities	2,018	1,966	1,932
Sales for resale	1,490	4,050	5,062
Total	21,199	23,306	23,378
OPERATING REVENUES:			
(Thousands)			
Electric Revenues:			
Residential	$ 476,441	$ 488,921	$ 436,984
Commercial and industrial	549,528	582,733	550,738
Public street and highway lighting	9,294	9,433	9,134
Other sales to public authorities	99,789	107,035	101,434
Sales for resale	43,001	89,945	95,529
Provision for rate refund	(3,417)	(14,963)	(18,000)
Miscellaneous	22,262	19,712	18,174
Total Electric Revenues	1,196,898	1,282,816	1,193,993
Non-utility subsidiary	158,270	164,436	120,991
Total	$ 1,355,168	$ 1,447,252	$ 1,314,984
NUMBER OF ELECTRIC CUSTOMERS:			
(At end of period)			
Residential	578,044	568,780	563,261
Commercial and industrial	81,175	79,572	78,799
Public street and highway lighting	249	248	248
Other sales to public authorities	10,198	10,074	9,842
Sales for resale	39	39	37
Total	669,705	658,713	652,187
RESIDENTIAL ELECTRIC SERVICE:			
Average annual use (kWh)	11,724	11,688	10,664
Average annual revenue	$ 828.86	$ 861.72	$ 779.21
Average price per kWh (cents)	7.07	7.37	7.31

FINANCE AND CONSTRUCTION

The Company meets its cash needs through internally generated funds, short-term borrowings and permanent financing. Cash flows from operations remained strong, which enabled the Company to internally generate the required funds to satisfy construction expenditures during 1994 and 1993.

Management expects that internally generated funds will be adequate over the next three years to meet OG&E's capital requirements. The primary capital requirements for 1995 through 1997 are estimated as follows:

(dollars in millions)	1995	1996	1997
Consolidated construction expenditures including AFUDC	$ 89	$ 89	$ 89
Maturities of long-term debt and sinking fund requirements	25	-	15
Total	$114	$ 89	$104

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 and sinking fund obligations. Approximately $7.4 million of the Company's construction expenditures budgeted for 1995 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 "Rate Structure, Load Growth and Related Matters."

OG&E's ability to sell additional securities on satisfactory terms to meet its capital needs is dependent upon numerous factors, including general market conditions for utility securities, which will impact OG&E's ability to meet earnings tests for the issuance of additional first mortgage bonds and preferred stock. Based on earnings for the twelve months ended December 31, 1994, and assuming an annual interest rate of 8.3 percent, OG&E could issue approximately $883 million in principal amount of additional first mortgage bonds under the earnings test contained in OG&E's Trust Indenture (assuming adequate property additions were available). Under the earnings test contained in OG&E's Restated Certificate of Incorporation and assuming none of the foregoing first mortgage bonds are issued, about $864 million of additional preferred stock at an assumed annual dividend rate of 7.9 percent could be issued as of December 31, 1994.

The Company will continue to use short-term borrowings to meet temporary cash requirements and has the necessary regulatory approvals to incur up to $400 million in short-term borrowings at any one time. The maximum amount of outstanding short-term borrowings during 1994 was $220 million.

OG&E intends to meet its customers' increased electricity needs during the foreseeable future by maintaining the reliability and increasing the utilization of existing capacity along with demand-side management. OG&E is not currently constructing new base-load generation and does not anticipate the need for another base-load plant in the foreseeable future.

As part of its Integrated Resource Plan ("IRP") for supplying energy through the next decade and beyond, OG&E is evaluating measures to keep its existing generating plants operating efficiently well past their traditional retirement dates. As long as the cost to keep existing plants operating reliably and efficiently is less than the cost of alternative sources of capacity, existing plants will be operated.

In accordance with the requirements of the Public Utility Regulatory Policies Act of 1978 ("PURPA") (see "Regulation and Rates, National Energy Legislation"), OG&E is obligated to purchase 110 megawatts of capacity annually from Smith Cogeneration, Inc. and 320 megawatts annually from Applied Energy Services, Inc. AES, another cogenerator. In 1986, a contract was signed with Sparks Regional Medical Center to purchase energy not needed by the hospital from its nominal seven megawatt cogeneration facility. In 1987, OG&E signed a contract to purchase up to 100 megawatts of capacity from Mid-Continent Power Company, Inc. This purchase of capacity is currently planned to begin in 1998 and carries no obligation on the part of OG&E to purchase energy. The purchases under each of these cogeneration contracts were approved by the appropriate regulatory commissions at rates set in accordance with PURPA.

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

REGULATION AND RATES

OG&E's retail electric tariffs in Oklahoma are regulated by the OCC, and in Arkansas are regulated 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.

For the year ended December 31, 1994, approximately 89 percent of OG&E's electric revenue was subject to the jurisdiction of the OCC, seven percent to the APSC, and four percent to the FERC.

RECENT REGULATORY MATTERS: On February 25, 1994, the OCC issued an order that, among other things, effectively lowered OG&E's rates to its Oklahoma retail customers by approximately $17 million annually and required OG&E to refund approximately $41.3 million. Of the $41.3 million refund, $39.1 million is associated with revenues prior to January 1, 1994, while the remaining $2.2 million related to 1994.

Enogex transports natural gas to OG&E for use at its gas-fired generating units and performs related gas gathering activities for OG&E. The entire $41.3 million refund related to the OCC's disallowance of a portion of the fees paid by OG&E to Enogex for such services in the past. Of the approximately $17 million annual rate reduction, approximately $9.9 million reflects the OCC's reduction of the amount to be recovered by OG&E from its Oklahoma customers for the future performance of such services by Enogex for OG&E. In accordance with the OCC's rate order and a stipulation approved by the OCC in July 1991, OG&E's electric rates are designed to permit OG&E to earn a 12 percent regulatory return on equity and the OCC staff is precluded from initiating an investigation of OG&E's rates for three years from February 25, 1994, unless OG&E's regulatory return on equity exceeds 12.75 percent.

In 1994, the Company underwent a significant restructuring effort and redesign of its operations to more favorably position itself for the competitive electric utility environment. The Company incurred $63.4 million of restructuring costs in 1994. Pending an OCC order, OG&E deferred the costs associated with a VERP and severance package in the third quarter of 1994. Between August 1, and December 31, 1994, the

amount deferred was reduced by approximately $14.5 million. In response to an application filed by OG&E on August 9, 1994, the OCC issued an order on October 26, 1994, that permitted OG&E to amortize the December 31, 1994, regulatory asset of $48.9 million over 26 months and reduced OG&E's electric rates by approximately $15 million annually, effective January 1995. Management anticipates that labor savings from the VERP and severance package will substantially offset the amortization of the regulatory asset and annual rate reduction of $15 million. Labor savings in 1994 approximated the amortization of the deferred amount and therefore, did not significantly impact 1994 results. However, approximately $6.5 million in other restructuring expenses reduced 1994 earnings by $0.10 per share. At December 31, 1994, the deferred amount was $48.9 million, which is included on the Consolidated Balance Sheets as Deferred Charges - Other.

Pursuant to an order from the APSC in July 1992, OG&E and other electric utilities serving customers in Arkansas were required to submit 20-year Integrated Resource Plans with the APSC. The IRP process required the utilities to document their plans for serving their customers' electric energy needs, taking into account the full range of alternatives, including new generating capacity, purchased power, energy conservation and efficiency, cogeneration and renewable energy sources, in order to provide adequate and reliable service to their electric customers at the lowest system cost. On October 5, 1994, the APSC issued an Order initiating a Notice of Inquiry with respect to integrated resource planning and energy efficiency investments in power generation and supply for electric utilities, and suspending proceedings in OG&E's IRP Docket until further notice. In essence, the APSC Order stated that before the APSC proceeds further with the pending dockets on IRP, including OG&E's, the ASPC should look more closely at the relationship between the Federal IRP standard and the "...changes occurring in the electric utility industry..." particularly with respect to competition. Because of the changing utility industry, the APSC has determined it should examine more closely whether IRP is appropriate given the movement of the industry away from regulation.

On October 5, 1994, the OCC issued an order instructing the OCC staff of the Public Utility Division ("PUD") to move forward with the development of OCC rules to implement the mandates of Sections 111 and 115 of the National Energy Policy Act of 1992, requiring OG&E and other electric utilities to each submit 20-year IRPs. The order instructs OCC staff to carry out this development through a collaborative process involving all affected parties. The completion date is scheduled for mid-to late 1995.

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 estimated cost-of-service for ratemaking, are charged to substantially all of the Company's electric customers through automatic fuel adjustment clauses, which are subject to periodic review by the OCC, the APSC and the FERC.

NATIONAL ENERGY LEGISLATION: The National Energy Act of 1978 imposes numerous responsibilities and requirements on OG&E. PURPA requires electric utilities, such as OG&E, to purchase electric power from, and sell electric power to, QFs and small power production facilities. Generally stated, electric utilities must purchase electric energy and production capacity made available by QFs and small power producers at a rate reflecting the cost that the purchasing utility can avoid as a result of obtaining energy and production capacity from these sources; rather than generating an equivalent amount of energy itself or purchasing the energy or capacity from other suppliers. OG&E has entered into agreements with four such cogenerators.

See "Finance and Construction." Electric utilities also must furnish electric energy to QFs on a non-discriminatory basis at a rate that is just and reasonable and in the public interest and must provide certain types of service which may be requested by QFs to supplement or back up those facilities' own generation.

The National Energy Policy Act of 1992 ("Energy Act") is expected to make some significant changes in the operations of the electric utility industry and the federal policies governing the generation and sale of electric power. The Energy Act, among other things, allows the FERC to order utilities to permit access to their electrical transmission systems and to transmit power produced by independent power producers at transmission rates set by the FERC. The Energy Act also provides funds to study electric vehicle technology, the effects of electric and magnetic fields, and institutes a tax credit for generating electricity using renewable energy sources. The Energy Act also is designed to promote competition in the development of wholesale power generation in the electric industry. It exempts a new class of independent power producers from regulation under the Public Utility Holding Company Act of 1935 and allows the FERC to order "wholesale wheeling" by public utilities to provide utility and non-utility generators access to public utility transmission facilities. Also, numerous states are considering proposals to require "retail wheeling". The Energy Act, these proposals and other factors are expected to significantly increase competition in the electric industry. The Company has taken steps in the past and intends to take appropriate steps in the future to remain a competitive supplier of electricity. Past actions include the redesign and restructuring effort in 1994 and the actions to reduce fuel costs, both of which have resulted in lower retail rates, especially for industrial customers. In 1995, the Company intends to make a transmission open access filing before the FERC, in compliance with the Energy Act, and the Company intends to implement Real Time Pricing for a pilot group of its retail customers. See "Rate Structure, Load Growth and Related Matters."

RATE STRUCTURE, LOAD GROWTH AND RELATED MATTERS

Two of OG&E's primary goals in its electric tariff designs are: (i) to increase electric revenues by attracting and expanding job-producing businesses and industries; and (ii) to encourage the efficient use of energy by all of its customers. In order to meet these goals, OG&E has reduced and restructured its rates to its key customers while at the same time implementing numerous energy efficiency programs and tariff schedules. These programs and schedules include: (i) residential energy audits promoting efficient energy use, and assistance programs that help residential customers live in comfortable homes with lower energy costs; (ii) the PEAKS program, which provides credit on a customer's bill for the installation of a device that periodically cycles off the customer's central air conditioner during peak summer periods; (iii) a load curtailment rate for industrial and commercial customers who can demonstrate a load curtailment of at least 300 kilowatts; (iv) 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 afternoons to non-peak hours; and (v) a thermal energy storage program that promotes the shifting of cooling loads to off-peak hours.

In 1994, OG&E's marketing efforts included thermal storage, electrotechnologies, an electric food service promotion and a heat pump promotion in the residential, commercial and industrial markets. Educating customers to use available time-of-use rates to lower their energy costs was also pursued. These rates can make commercial and industrial heating and cooling especially economical if power is used with thermal storage systems which chill water at night for cooling the next day.

To meet customers' electric power needs for their sensitive electronic equipment, OG&E began the Power Quality program several years ago. Through this program, a trained Power Quality team works with the customer by performing a thorough survey of wiring and grounding, transient surge protection checks and power monitoring. The customer and the team then develop solutions and alternatives to power needs at the facility.

OG&E continues studying programs such as Real Time Pricing to keep its electric tariffs attractive and to control peak demand growth. Real Time Pricing is a service option which prices electricity so that current price varies hourly with short notice to reflect current expected cost. The technique will allow a measure of competitive pricing, a broadening of customer choice, balancing of electricity usage and capacity in the short and long term, and help customers to control their costs. OG&E will implement a pilot program in 1995 with some industrial customers.

Other programs include the use of high efficiency lighting and ballasts, high efficiency motors, high efficiency air conditioners or chillers, use of home automation systems, high-tech refrigeration equipment, adjustable speed drives on electric motors, high-tech electric water heating systems, heating and cooling demand controls and time scheduling of electric appliances, such as water heaters. OG&E has also expanded its Positive Energy Home finance programs for customers to include heat pump water heaters and ground source heat pumps.

OG&E currently does not anticipate the need for new baseload generating plants in the foreseeable future. For further discussion, see "Finance and Construction."

FUEL SUPPLY

During 1994, approximately 28 percent of the OG&E-generated energy was produced by natural gas-fired units and 72 percent by coal-fired units. It is estimated that the fuel mix for 1995 through 1999, based upon expected generation for these years, will be as follows:

	1995	1996	1997	1998	1999
Natural Gas	18%	22%	24%	26%	28%
Coal	82%	78%	76%	74%	72%

The average cost of fuel used, by type, per million Btu for each of the 5 years was as follows:

	1994	1993	1992	1991	1990

Natural Gas	$3.58	$3.64	$3.48	$3.14	$3.06
Coal	$0.78	$1.16	$1.18	$1.21	$1.38
Weighted Avg	$1.58	$1.92	$1.88	$1.96	$2.08

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

GAS-FIRED UNITS: OG&E has approximately 740 natural gas purchase contracts covering approximately 430 wells and delivery points. These contracts cover an estimated 153 billion cubic feet of connected reserves.

OG&E acquires some natural gas at the wellhead under purchase contracts which contain provisions allowing the owners to require prepayments for gas if certain minimum quantities are not taken (see Note 9 of Notes to Consolidated Financial Statements). At December 31, 1994, outstanding prepayments for gas, including the amounts classified as current assets, under these contracts were approximately $10.9 million (including $10 million accrued but not yet paid). A contract with Oklahoma Natural Gas Company for additional peaking gas is renewed yearly. The need for this peaking gas contract will be eliminated as soon as an 8.0 BCF gas storage facility becomes fully operational.

In 1993, OG&E began utilizing a natural gas storage facility which helps OG&E lower fuel costs and receive greater value from its remaining take-or-pay gas contracts. By diverting natural gas into storage, OG&E is able to use as much coal as possible to generate electricity, and use gas from storage when needed to meet increases in demand for electricity. In 1995, gas storage will give OG&E the flexibility to generate about 82 percent of its electricity with coal, the highest percentage in OG&E's history. This fuel mix change, along with fuel price reductions will allow OG&E to reduce its fuel costs in 1995 by an estimated $37 million compared to 1994.

COAL-FIRED UNITS: All of OG&E coal units, with an aggregate capacity of 3,045 megawatts, are designed to burn low-sulfur western coal. OG&E purchases coal under a mix of long and short-term contracts. OG&E currently has a long-term, multiple option agreement with Atlantic Richfield Company to supply coal for these units. The combination of all coal has an average sulfur content of 0.4 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.

During 1994, OG&E burned a total of 8.1 million tons of coal. Based upon the average sulfur content of Wyoming coal, OG&E's units have an approximate emission rate of 0.78 pounds of sulfur dioxide per million Btu. See related discussion in "Environmental Matters." In 1993, OG&E negotiated new rail transportation contracts for coal beginning in 1994, which resulted in lower transportation rates.

The Wyoming coal is transported to OG&E's generating stations, a distance of about 1,000 miles, by unit trains. In 1994, OG&E leased 1,930 coal cars, of which 1,367 were aluminum, at an approximate annual rental cost of $5.6 million. The efficiencies related to this newer design of high volume aluminum body railcar have reduced, by approximately six percent, the number of trips from Wyoming and reduced railcar maintenance expenses. On July 1, 1994, the lease expired on 426 steel railcars and they were returned to the lessor.

ENVIRONMENTAL MATTERS

OG&E 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 expenditures for capital, operating, maintenance and other costs to preserve and enhance environmental quality will be approximately $46 million during 1995, compared to approximately $47 million in 1994. OG&E is continually evaluating its environmental programs to ensure compliance with existing and proposed environmental legislation and regulations and to position itself in a competitive market.

The Company continues to explore options to comply with the Clean Air Act Amendments of 1990 ("CAAA"). Since all of OG&E's coal-fired generating units currently burn low-sulfur coal, OG&E will not need to take any steps to comply with the new sulfur dioxide emission limits until January 1, 2000. In compliance with Title IV of the CAAA, the Company has completed installation of continuous emission monitors ("CEMs") on each of its five coal-fired generating units and three of its 12 gas-fired generating units. Expenditures on CEMs in 1994 totalled approximately $6 million. The Environmental Protection Agency ("EPA") established a time extension for installation of CEMs on gas-fired units which allowed the Company to defer CEM installation on the remaining nine units subject to the requirements of Title IV. Completion of this project is expected to cost approximately $1 million during 1995. The CAAA Title V operating permits are expected to cost approximately $400,000 in 1995.

The CAAA will also regulate emissions of nitrogen oxides and certain air toxic compounds. Although final regulations concerning all of these issues have not been written, additional capital expenditures may be necessary in future years. The Company will continue to examine all alternatives to comply with the CAAA as part of its Integrated Resource Planning process. This planning approach will assure that the Company employs the least cost option to comply with the CAAA and be in a competitive position to market its services.

During 1992, OG&E disclosed to the EPA discrepancies in the 1991 annual report required by the Toxic Substance Control Act ("TSCA"). These discrepancies were administrative in nature and presented no harm to the environment and presented no health problems to our Company members or the public. However, the Company has instituted specific systems and measures to correct each of the reported discrepancies. On December 15, 1994, the Company was notified by the EPA that the EPA had commenced reviewing the matter, and a response from the EPA may be forthcoming in 1995. No actions were taken by the EPA on this matter during 1994. See "Item 3. Legal Proceedings" for additional discussion of this matter.

The Company remains a party to three separate actions brought by the EPA concerning cleanup of disposal sites for hazardous waste and is involved in three other matters with the EPA. See "Item 3. Legal Proceedings."

ENOGEX

OG&E's wholly-owned non-utility subsidiary, Enogex Inc., is the 37th largest pipeline in the nation in terms of miles of pipeline. Enogex Inc.'s primary operations consist of transporting natural gas through its intra-state pipeline to various customers (including OG&E), buying and selling natural gas to third parties, selling natural gas liquids extracted by its natural gas processing plants and investing in natural gas exploration and production activities. At December 31, 1994, Enogex Inc. had five wholly-owned subsidiaries, Enogex Products Corporation ("Products"), Enogex Services Corporation ("Services"), Enogex Exploration Corporation ("Exploration"), ENGL Corporation ("ENGL"), and Clinton Gas Transmission, Inc. ("Clinton"). Enogex also owns an 80% interest in Centoma Gas Systems, Inc. ("Centoma"). Products owns interests in and operates three natural gas processing plants and marketed natural gas liquids through the end of 1994. Exploration is engaged in investing in the exploration and production of oil and natural gas and the purchase of oil and gas reserves. ENGL owns and operates a natural gas processing plant and marketed the natural gas liquids through the end of 1994. Services and Clinton are engaged in the marketing (buying and selling) of natural gas and beginning in 1995, Services will also market natural gas liquids of Products and ENGL. Centoma both purchases and gathers gas for subsequent processing at one of three processing plants, two of which are owned by Products. The residue gas is then sold under a combination of contract and spot market prices.

For the year ended December 31, 1994, and before elimination of intercompany items between OG&E and Enogex, Enogex's consolidated revenues and net income were approximately $203.1 million and $10.0 million, respectively, as indicated in the following table:

(dollars in millions)	1994 Revenues		1994 Net Income	
Enogex Inc.	$ 57.7		$10.0	(a)
Products	18.7		2.8	
Services	107.7		0.7	
Exploration	5.3		3.2	
ENGL	5.7		0.3	
Clinton	17.6		0.1	
Centoma	3.5		0.0	
Eliminations within Enogex	(13.1)	(b)	(7.1)	
Enogex consolidated amounts	$203.1		$10.0	

(a) Includes $7.1 million of net income from Products, Services, Exploration, ENGL, Clinton and Centoma.

(b) Consists of intercompany natural gas transmission fees of $1.8 million and sales of natural gas products amounting to $11.3 million.

Enogex's natural gas transportation business in Oklahoma consists primarily of gathering and transporting natural gas for OG&E and on an interruptible basis, third-party-owned gas. Enogex's system consists of over 3,000 miles of pipeline, which extends from the Arkoma Basin in eastern Oklahoma to the Anadarko Basin in western Oklahoma. Since 1960, Enogex has had a gas transmission contract with OG&E under which Enogex transports OG&E's natural gas supply on a fee basis. Enogex also provides accounting services and assists in payments to producers and suppliers under the contract. Under the gas transmission contract, OG&E agrees to tender to Enogex and Enogex agrees to transport, on a firm, load-following basis, all of OG&E's natural gas requirements for boiler fuel for its seven gas-fired electric generating stations. In 1994, Enogex transported 132 Bcf of natural gas; of which approximately 61 Bcf, or about 46 percent, was delivered to OG&E's electric generating stations and storage facility, which resulted in approximately 78 percent of Enogex Inc.'s revenue of $57.7 million for 1994. See "Regulation and Rates."

Enogex's pipeline system also gathers and transports natural gas destined for interstate markets through interconnections in Oklahoma with other pipeline companies. Among others, these interconnections include Panhandle Eastern Pipeline, Williams Natural Gas Pipeline, Natural Gas Pipeline Company of America, Northern Natural Gas Company, Arkla Energy Resources, Phillips Seagas Pipeline, ANR Pipeline Company and Ozark Gas Transmission Company.

The rates charged by Enogex for transporting natural gas on behalf of an interstate natural gas pipeline company or a local distribution company served by an interstate natural gas pipeline company are subject to the jurisdiction of FERC under Section 311 of the Natural Gas Policy Act. The statute entitles Enogex to charge a "fair and equitable" rate that is subject to review and approval by FERC. This rate review may involve an administrative-type trial and an administrative appellate review. In addition, Enogex has agreed to open its system to all interstate shippers that are interested in moving natural gas through the Enogex system. Enogex is required to conduct this transportation on a non-discriminatory basis, although this transportation is subordinate to that performed for OG&E. This decision does not increase appreciably the federal regulatory burden on Enogex, but does give Enogex the opportunity to utilize any unused capacity on an interruptible basis and thus increase its transportation revenues.

The fees charged by Enogex for transporting natural gas for OG&E and other intrastate shippers are not subject to FERC regulation. With respect to state regulation, the fees charged by Enogex for any intrastate transportation service have not been subject to direct state regulation by the OCC. Even though the intrastate pipeline business of Enogex is not directly regulated, the OCC, the APSC and the FERC have the authority to examine the appropriateness of any transportation charge or other fees paid by OG&E to Enogex, which OG&E seeks to recover from ratepayers. See "Regulation and Rates" for a further discussion of this matter and the OCC's ruling on the fees paid by OG&E to Enogex.

Products has been active since 1968 in the processing of natural gas and marketing of natural gas liquids. Products has a 50 percent interest in and operates a natural gas processing plant near Calumet, Oklahoma, which can process 250 Mmcf of natural gas per day. Products also owns two other natural gas processing plants in Oklahoma, which have, in the aggregate, the capacity to process approximately 23 Mmcf of natural gas per day. ENGL owns one natural gas processing plant in Oklahoma, which has the capacity to process approximately 18 Mmcf of natural gas per day. Products' natural gas processing plant operations consist of off-lease extraction of liquids from natural gas that is transported through the Enogex pipeline, while ENGL's natural gas processing operations consists of off-lease extraction of liquids from an unaffiliated pipeline. The raw gas stream is processed and converted into marketable ethane, propane, butane, and natural gasoline mix. The residue gas remaining after the liquid products have been extracted consists primarily of methane.

Commercial grade propane is sold on the local market and the marketing of all other natural gas liquids extracted by Products and ENGL was handled through independent brokers. Beginning in 1995, the natural gas liquids will be marketed by Services. The natural gas liquids are delivered to Conway, Kansas (which is one of the nation's largest wholesale markets for gas liquids), where they are sold on the spot market, commonly referred to as Group 140.

In processing and marketing natural gas liquids, the Enogex companies compete against virtually all other gas processors selling natural gas liquids. The Enogex companies believe they 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 the Enogex companies specifically, the volume of natural gas processed at their plants is dependent upon the volume of natural gas transported through the pipeline system located "behind the plants" (i.e. the Enogex pipeline for Products and an unaffiliated pipeline for ENGL). If the volume of natural gas transported by such pipeline increases "behind the plants," then the volume of liquids extracted by Products and ENGL should normally increase.

Services is a natural gas and natural gas liquids marketing company serving both producers and consumers of natural gas by buying natural gas at the wellhead and from other sources in Oklahoma and other states, and reselling the gas to local distribution companies, utilities other than OG&E and industrial purchasers both within and outside Oklahoma. It also serves Products and ENGL by purchasing and marketing the natural gas liquids they produce.

Although the margin on gas sales by Services is relatively small, approximately 50 percent of the natural gas purchased and resold is transported through the Enogex Inc. pipeline to one or more interstate pipelines that deliver the gas to markets. Thus, in addition to purchasing and selling natural gas, Services seeks to use the space available in the Enogex Inc. pipeline and increase the amount of natural gas available for processing by Products. Clinton is engaged in essentially the same business as Services.

Enogex Inc. is committed to continue the activities of Services in order to increase the amount of natural gas transported through the pipeline and the amount of natural gas processed by Products.

In its marketing and transportation services for third parties, Enogex Inc., Services and Clinton encounter competition from other natural gas transporters and marketers and from available alternative energy sources. The effect of competition from alternative energy sources is dependent upon the availability and cost of competing supply sources.

Volumes of natural gas transported by Enogex Inc. for third parties and the revenues derived from such activities increased from 1993. The contributing factors for the increase were specific projects implemented to strengthen Enogex's position, with other similar projects under consideration.

Services and Clinton compete with all major suppliers of natural gas and natural gas liquids in the geographic markets they serve. For natural gas, those geographic markets are primarily the areas served by pipelines with which Enogex is interconnected. Although the price of the gas is an important factor to a buyer of natural gas from Services, the primary factor is the total cost (including transportation fees) that the buyer must pay. Natural gas transported for Services by Enogex Inc. is billed at the same rate Enogex Inc. charges for comparable third-party transportation. Exploration was formed in 1988 primarily to engage in the exploration and production of natural gas. Exploration has focused its drilling activity in the Antrim Devonian shale trend in the state of Michigan and also has interests in Oklahoma. As of December 31, 1994, Exploration had interests in 273 active wells and total assets, including such interests, of approximately $38 million.

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ITEM 2. PROPERTIES.

OG&E owns and operates an interconnected electric production, transmission and distribution system, located in Oklahoma and western Arkansas, which includes eight active generating stations with an aggregate active capability of 5,637 megawatts. The following table sets forth information with respect to present electric generating facilities:

Station & Unit		Fuel	Year Installed	Unit Capability (Megawatts)	Station Capability (Megawatts)
Seminole	1	Gas	1971	549	
	2	Gas	1973	507	
	3	Gas	1975	500	1,556
Muskogee	3	Gas	1956	184	
	4	Coal	1977	500	
	5	Coal	1978	500	
	6	Coal	1984	515	1,699
Sooner	1	Coal	1979	505	
	2	Coal	1980	510	1,015
Horseshoe	6	Gas	1958	178	
Lake	7	Gas	1963	238	
	8	Gas	1969	394	810
Mustang	1	Gas	1950	58	Inactive
	2	Gas	1951	57	Inactive
	3	Gas	1955	122	
	4	Gas	1959	260	
	5	Gas	1971	64	446
Conoco	1	Gas	1991	26	
	2	Gas	1991	26	52
Arbuckle	1	Gas	1953	74	Inactive
Enid	1	Gas	1965	12	
	2	Gas	1965	12	
	3	Gas	1965	12	
	4	Gas	1965	12	48
Woodward	1	Gas	1963	11	11
Total Active Generating Capability (all stations)					5,637

At December 31, 1994, OG&E's transmission system included 71 substations with a total capacity of approximately 17.2 million kVA and approximately 4,283 structure miles of lines. The distribution system included 338 substations with a total capacity of approximately 6.1 million kVA, 21,113 structure miles of overhead lines, 1,626 miles of underground conduit and 6,394 miles of underground conductor.

Substantially all of OG&E's electric facilities are subject to a direct first mortgage lien under the Trust Indenture securing OG&E's first mortgage bonds.

Enogex owns: (1) over 3,000 miles of natural gas pipeline extending from the Arkoma Basin in eastern Oklahoma to the Anadarko Basin in western Oklahoma; (2) a 50 percent interest in a natural gas processing plant near Calumet, Oklahoma, which has the capacity to process 250 Mmcf of natural gas per day; (3) three other natural gas processing plants in Oklahoma, which have, in the aggregate, the capacity to process approximately 41 Mmcf of natural gas per day; and (4) an 80 percent interest in approximately 110 miles of gas gathering pipeline owned by Centoma.

During the three years ended December 31, 1994, the Company's gross property, plant and equipment additions approximated $405 million and gross retirements approximated $67 million. Over 95 percent of these additions were provided by internally generated funds. The additions during this three-year period amounted to approximately 10.6 percent of total property, plant and equipment at December 31, 1994.

ITEM 3. LEGAL PROCEEDINGS.

1. Puritan Oil and Gas Corp., and other Plaintiffs, filed an amendment to a petition on February 19, 1993, to an action previously filed in the District Court of Oklahoma County, involving an alleged breach of oil and gas contract by OG&E. This case was removed to the United States District Court for the Western District of Oklahoma. Enogex Inc. was also joined as a Defendant in the action. Plaintiffs allege that OG&E and Enogex were in violation of the Federal Racket Influenced and Corrupt Act ("RICO"). OG&E filed its Motion to Dismiss the RICO claim on March 26, 1993. Plaintiffs allege the Defendants refused to honor contractual obligations in certain gas purchase contracts. The underlying dispute on the gas purchase contracts arises in the ordinary course of OG&E's business and involves whether OG&E must purchase gas thereunder, where the contract provides for certain requirements to be maintained by the well. Actual damages under the RICO claim are sought in an amount of $2,000,000. RICO provides that these damages be trebled in the event of an adverse verdict. Punitive damages under the RICO claim are also sought in the amount of $1,000,000.

On January 4, 1994, the United States District Court for the Western District of Oklahoma entered its Order and dismissed Plaintiffs' RICO claim as well as Plaintiffs' claim for punitive damages under RICO. On January 14, 1994, Plaintiffs filed a Motion to Alter or Amend Judgment seeking leave of Court to file its Amended Complaint asserting different allegations under RICO. On January 31, 1994, the Court denied Plaintiffs' motion.

Plaintiffs filed their Appeal with the United States Court of Appeals for the 10th Circuit. In addition, the United States District for the Western District of Oklahoma remanded the breach of contract claim to the District Court of Oklahoma County, Oklahoma. By Order filed January 11, 1995, the Court dismissed the appeal pursuant to a stipulation of the parties. The RICO case is now dismissed.

Management believes the outcome of this proceeding will not have a material adverse effect on the Company's consolidated financial position or its results of operations for numerous reasons, which include that the underlying dispute between the parties is a contractual dispute under a gas purchase contract. Management intends to vigorously pursue the defense of this matter.

2. On July 8, 1994, an employee of OG&E filed a lawsuit in state court against OG&E in connection with OG&E's voluntary early retirement package. The case has been removed to the U.S. District Court in Tulsa, Oklahoma. The lawsuit purports to be a class action and alleges violation of Title VII, ERISA, intentional infliction of emotional distress and other issues.

On August 23, 1994, the trial court sustained OG&E's Motion to Dismiss Plaintiffs' Complaint, in its entirety. On September 12, 1994, Plaintiffs filed an Amended Complaint alleging substantially the same allegations which were in the original Complaint. On October 10, 1994, Defendants filed a Motion to Dismiss Counts II, IV, V, VI and VII of Plaintiffs Amended Complaint and filed responsive pleadings to Counts I and III. With regard to those two Counts, additional investigation will be required to determine whether or not Plaintiffs can successfully pursue those claims. While the Company cannot predict the precise outcome of the proceeding, the Company continues to believe that the lawsuit is without merit and will not have a material adverse effect on its consolidated results of operations or financial condition.

3. On June 30, l986, the United States government filed suit against OG&E and 36 other defendants in case number CIV-86-l40l W, in the United States District Court ("USDC") for the Western District of Oklahoma. The Complaint generally alleged that a total of l8 million gallons of hazardous and toxic waste were contained at the Hardage Criner site located approximately 30 miles south of Oklahoma City, and that the government had expended, as of the date of the filing of the Complaint, $l.44 million related to the site. The 37 defendants are divided into three classes: 33 "generator" defendants, of which the Company is one; three "transporter" defendants; and the owner of the site, Mr. Royal Hardage.

It is estimated that over 200 other entities, not named in the government's Complaint, also disposed of materials at the site. OG&E disposed of an estimated 130,000 gallons at the site, or less than 1 percent of the total volume of waste. OG&E, along with each other Potentially Responsible Party ("PRP"), could be held jointly and severally liable for the remediation of the site. In August 1990, the USDC issued its rulings on the appropriate method for cleanup of the site. The USDC selected the containment remedy proposed by the Hardage Criner Steering Committee Defendants (the "Committee"), of which OG&E is a member, with several modifications. The remedy ordered by the USDC was estimated to cost approximately $60 million.

The design and construction of the remedy is 99% complete. On December 1, 1994, a tour of the remedy facilities was conducted; present were representatives of PRPs, EPA and the State agencies.

Settlements have been reached with numerous parties that were not members of the Committee for their share of costs incurred. The money collected through these settlements is being used to finance the remedy and to reimburse the government for response costs.

Even though the settlement funds, plus interest and the United States contribution will raise a substantial portion of the monies required, any remaining amounts that OG&E and the other Committee members are likely to pay may still be substantial due to maintenance of the remedy over time.

The Committee members have reached an Agreement to pay the on-going maintenance costs based on each company's respective volume of waste sent to the site. OG&E's share of the total is 2.33 percent, or approximately $1.4 million.

While it is not possible to determine the precise outcome of this matter, in the opinion of management, OG&E's ultimate liability for the cleanup costs of this site will not have a material adverse effect on OG&E's financial position or its results of operations. Management's opinion is based on the following: (1) the cleanup

costs already paid by certain parties; (2) the financial viability of the other PRPs; (3) the portion of the total waste disposed at this site attributable to OG&E; and (4) the remedy construction is substantially complete. Management also believes that costs incurred in connection with this site, which are not recovered from insurance carriers or other parties, may be allowable costs for future ratemaking purposes.

4. OG&E is also involved, along with numerous other PRPs, in an EPA administrative action involving the facility in Holden, Missouri, of Martha C. Rose Chemicals, Inc. ("Rose"). Beginning in early 1983 through 1986, Rose was engaged in the business of brokering of polychlorinated biphenyls ("PCBs") and PCB items, processing of PCB capacitors and transformers for disposal, and decontamination of mineral oil dielectric fluids containing PCBs. During this time period, various generators of PCBs ("Generators"), including OG&E, shipped materials containing PCBs to the facility. Contrary to its contractual obligation with OG&E and other Generators, it appears that Rose failed to manage, handle and dispose of the PCBs and the PCB items in accordance with the applicable law. Rose has been issued citations by both the EPA and the Occupational Safety and Health Administration. OG&E, along with the other PRPs, could be held jointly and severally liable for the remediation of the site.

In March 1986, Rose abandoned its facility in Holden, Missouri, and subsequently notified certain Generators of its unwillingness and/or inability to come into compliance with the PCB rules and regulations and to properly dispose of such PCBs and PCB items at the facility. In addition to PCBs and PCB items at the Rose facility, the EPA believes that contaminated soils, sediments and/or sludge may be present off-site.

Several Generators, including OG&E, formed a Steering Committee to investigate and possibly clean up the Rose facility. Currently, OG&E management's estimate of the total cost for cleanup of the Rose facility is in the range of $23 to $31 million, of which $18.5 million has already been collected from certain parties.

The Company estimates its share of the total hazardous wastes at the Rose facility to be less than six percent. A Settlement Agreement between AEGIS Insurance Company and OG&E was reached in 1994. Although the Company cannot predict the precise outcome of this matter, management believes that OG&E's ultimate liability for the cleanup costs of this site will not have a material adverse effect on OG&E's financial position or its results of operations. Management's opinion is based on the following: (1) the cleanup costs already paid by certain parties; (2) the financial viability of the other PRPs; (3) the portion of the total waste disposed at this site attributable to OG&E and (4) the Company's settlement agreement with its insurer. Management also believes that costs incurred in connection with this site, which are not recovered from insurance carriers or other parties, may be allowable costs for future ratemaking purposes.

5. During the Third Quarter of 1992 OG&E began a voluntary review of information contained in the 1991 annual report required under the Toxic Substance Control Act ("TSCA"). The initial result of the review revealed some discrepancies in operating practices and documentation.

EPA, Region VI, was notified of these initial discrepancies in December, 1992. Because it suspected that additional discrepancies might be discovered during the continuing review/audit, OG&E reached an agreement on January 12, 1993, with the EPA, Region VI, concerning the notification and reporting requirements of any newly discovered discrepancies.

After further investigation, OG&E reported in September 1993 numerous additional discrepancies to the EPA, Region VI. Many of the discrepancies could be deemed violations of the regulations under TSCA. The discrepancies principally concerned the TSCA regulations relating to PCB handling and record keeping

requirements. However, to the Company's knowledge, none of the activities involved releases of materials into the environment or caused harm to any individuals. Under the TSCA regulations, the EPA has the authority to assess a maximum fine of up to $25,000 per day, and to treat each day of violation as the basis for a separate fine. OG&E has taken and is taking corrective action to remedy the discrepancies.

The position of EPA and OG&E is that they are currently in pre-settlement negotiations. No fines have been assessed as of this date. Since this matter is currently being negotiated, OG&E does not know the amount of fines that the EPA may seek. The amount of the fine is dependent upon numerous interpretative issues under the TSCA regulations and potentially could be in an amount significant to the Company's results of operations. However, at the present time, the Company does not expect that the amount of the fine will have a material adverse effect on its consolidated financial position or its results of operations based primarily on having voluntarily reported the discrepancies to the EPA coupled with the Company's efforts to remedy the discrepancies and the lack of releases into the environment or harm to individuals. On December 15, 1994, the Company was notified by the EPA that the EPA had commenced reviewing the matter, and a response from the EPA may be forthcoming in 1995.

6. 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.

The Notice of Letter, a formal demand for reimbursement of past and future incurred costs (past costs are approximately $1.3 million), provided for a negotiation period of 60 days and encouraged the PRPs to perform or finance the response activities as set forth in the Record of Decision ("ROD") and the Draft Statement of Work ("SOW").

The ROD addresses the source of contamination both on and off the site and is divided into two operable units: 1) Source Control Operable Unit, the remedy of which is addressed with the SOW and has an estimated cost of $6.4 million; and 2) Groundwater Operable Unit, which is still being evaluated to assess the extent of contamination in the groundwater and any plumes. The cost of remediation for this Unit cannot be estimated at this time.

As to the Source Control Operable Unit and as a result of the EPA's Notice Letter, companies listed as PRPs (including OG&E) held several meetings to determine whether or not they should form a Steering Committee, whether additional research into volumetric shares should be conducted and a response, if any, to be sent to the EPA. Several but not all of the 46 companies have signed a very limited Participation Agreement, the purpose of which is to negotiate with the EPA.

On March 31, 1993, OG&E joined with the signatories to the limited Participation Agreement in making a settlement offer to the EPA.

The EPA met with representatives of the PRPs group on June 11, 1993, to discuss the current developments taking place. The EPA is currently considering a modification of the remedy for the Source Control Operable Unit because the remedy was apparently selected without giving consideration to the

presence of listed hazardous waste, although the presence of this waste was documented in the Record of Decision. The EPA explained at the meeting that it will likely not make a decision in the near future concerning the remedy for the Source Control Operable Unit. The EPA informed the participating PRPs that it would not pursue them through the issuance of a unilateral administrative order relating to the Special Notice Letters.

As to the Groundwater Operable Unit, OG&E declined to either participate in conducting or financing any remedial activities. No further action on the Groundwater Operable Unit has been taken by the EPA.

On February 1, 1994, OG&E received a Section 104 Letter from the EPA, Region VI, which asked for either participation in or financing of a Removal Action calling for netting of a 2.5 acre on-site sludge lagoon to preclude access to wildlife. The PRP Group, for various reasons, declined on February 10, 1994, to participate or finance the Removal Action.

On December 16, 1994, OG&E received a letter from EPA stating that it was waiving the Special Notice procedures under Section 122(e) in regard to the Remedial Design/Remedial Action for the second operable unit. This is based on the fact that (1) an offer for both operable units is presently being negotiated and (2) there is a strong indication that the PRPs will not perform the remedy. EPA hopes to conclude de minimis settlement negotiations and have a signed settlement document by April 28, 1995. It is believed at this time that OG&E is a de minimis party, in which case its liability would not be significant.

Due to the present stage of this matter, the total cost of the cleanup of the site and the Company's ultimate liability cannot be estimated. Nevertheless, management believes that OG&E's ultimate liability for the cleanup costs of this site will not have a material adverse effect on the Company's consolidated financial position or its results of operations. Management's opinion is based on the financial viability of the other PRPs and the portion of the total waste disposed at this site attributable to OG&E. Management also believes that costs incurred in connection with this site, which are not recovered from insurance carriers or other parties, may be allowable costs for future ratemaking purposes.

7. As previously reported, OG&E was aware of an asbestos problem at its former Osage Plant. During 1994, the Company determined that it had no material liability with respect to this matter.

8. OG&E has been requested by the EPA to permit the inspection of two separate properties owned by OG&E for possible hazardous substances, pollutants or contaminants. These sites were used many years ago by OG&E or certain companies acquired by OG&E for manufacturing gas from coal. In connection with manufacturing gas, various by-products were produced (including coal-tar and other potentially harmful materials), which could remain on the sites. During 1994, the Company determined that it had no material liability with respect to these sites.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS.

Not applicable.

EXECUTIVE OFFICERS OF THE REGISTRANT.

The following persons were Executive Officers of the Registrant as of March 15, 1995:

Name	Age	Title
James G. Harlow Jr.	60	Chairman of the Board, President and Chief Executive Officer
Patrick J. Ryan	56	Vice Chairman
Al M. Strecker	51	Senior Vice President - Finance and Administration
Steven E. Moore	48	Senior Vice President - Law and Public Affairs
Melvin D. Bowen Jr.	53	Vice President - Power Delivery
Jack T. Coffman	51	Vice President - Power Supply
Michael G. Davis	45	Vice President - Marketing and Customer Services
James R. Hatfield	37	Treasurer
Don L. Young	54	Controller
Donald R. Rowlett	37	Assistant Controller
Irma B. Elliott	56	Secretary

No family relationship exists between any of the Executive Officers of the Registrant. Each Officer is to hold office until the Board of Directors meeting following the next Annual Meeting of Shareowners, currently scheduled for May 18, 1995.

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

Name	Business Experience	
James G. Harlow Jr.	1990-Present:	Chairman of the Board, President and Chief Executive Officer

Patrick J. Ryan	1994-Present:	Vice Chairman
	1990-1994:	Executive Vice President and Chief Operating Officer
Al M. Strecker	1994-Present:	Senior Vice President - Finance and Administration
	1991-1994:	Vice President and Treasurer
	1990-1991:	Vice President, Secretary and Treasurer
Steven E. Moore	1994-Present:	Senior Vice President-Law and Public Affairs
	1990-1994:	Vice President - Law and Public Affairs
Melvin D. Bowen Jr.	1994-Present:	Vice President - Power Delivery
	1990-1994:	Metro Region Superintendent
Jack T. Coffman	1994-Present:	Vice President - Power Supply
	1990-1994:	Manager - Generation Services
Michael G. Davis	1994-Present:	Vice President - Marketing and Customer Services
	1992-1994:	Director - Marketing Division
	1990-1992:	Manager - Industrial Services

Name	Business Experience	
James R. Hatfield	1994-Present:	Treasurer
	1994:	Vice President - Investor Relations & Corporate Secretary - Aquila Gas Pipeline Corporation (an intrastate gas pipeline subsidiary of UtiliCorp United Inc.)
	1990-1993:	Assistant Treasurer - UtiliCorp United Inc. (an electric and natural gas utility company)
Don L. Young	1990-Present:	Controller
Donald R. Rowlett	1994-Present:	Assistant Controller
	1992-1994:	Senior Specialist -

		Tax Accounting
	1990-1992:	Specialist - Tax Accounting
Irma B. Elliott	1991-Present:	Secretary
	1990-1991:	Assistant Secretary

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 "OklaGE" 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.

	1994			1993		
	Dividend Paid	High	Low	Dividend Paid	High	Low
First Quarter	$0.66 1/2	$37 1/4	$33 1/2	$0.66 1/2	$35 7/8	$33
Second Quarter	0.66 1/2	36 1/2	29 3/8	0.66 1/2	37 5/8	33 3/4
Third Quarter	0.66 1/2	34 3/8	29 5/8	0.66 1/2	38 5/8	34
Fourth Quarter	0.66 1/2	34 1/4	32	0.66 1/2	38 5/8	32 7/8

The number of record holders of Common Stock at December 31, 1994, was 44,464. The book value of the Company's Common Stock at December 31, 1994, was $22.83.

ITEM 6. SELECTED FINANCIAL DATA.

HISTORICAL DATA

	1994	1993	1992	1991	1990
SELECTED FINANCIAL DATA (dollars in thousands except for per share data)					
Operating revenue	$ 1,355,168	$ 1,447,252	$ 1,314,984	$ 1,314,770	$ 1,230,769
Operating expenses	1,154,702	1,252,099	1,137,980	1,103,683	1,019,510
Operating income	200,466	195,153	177,004	211,087	211,259
Other income and deductions .	(2,167)	(1,301)	(567)	(471)	(263)
Interest charges	74,514	79,575	76,725	76,700	71,798
Net income	123,785	114,277	99,712	133,916	139,198
Preferred dividend requirements	2,317	2,317	2,317	2,317	2,467
Earnings available for common	$ 121,468	$ 111,960	$ 97,395	$ 131,599	$ 136,731
Long-term debt	$ 730,567	$ 838,660	$ 838,654	$ 853,597	$ 853,540
Total assets	$ 2,782,629	$ 2,731,424	$ 2,590,083	$ 2,566,089	$ 2,522,907
Earnings per average common share	$ 3.01	$ 2.78	$ 2.42	$ 3.27	$ 3.38
CAPITALIZATION RATIOS					
Common equity	54.13%	50.51%	50.36%	50.20%	49.44%
Cumulative preferred stock .	2.94%	2.78%	2.79%	2.75%	2.80%
Long-term debt	42.93%	46.71%	46.85%	47.05%	47.76%
INTEREST COVERAGES					
Before federal income taxes (including AFUDC)	3.59X	3.32X	3.05X	3.66X	3.91X
(excluding AFUDC)	3.58X	3.32X	3.04X	3.63X	3.87X
After federal income taxes					
(including AFUDC)	2.64X	2.43X	2.29X	2.70X	2.84X
(excluding AFUDC)	2.62X	2.42X	2.28X	2.66X	2.79X

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

MANAGEMENT'S DISCUSSION AND ANALYSIS

OVERVIEW

(THOUSANDS EXCEPT PER SHARE AMOUNTS)	1994	1993	1992	PERCENT CHANGE FROM PRIOR YEAR 1994	1993
Operating revenues	$1,355,168	$1,447,252	$1,314,984	(6.4)	10.1
Earnings available for common stock .	$ 121,468	$ 111,960	$ 97,395	8.5	15.0
Average shares outstanding	40,344	40,328	40,310	--	--
Earnings per average common share . .	$ 3.01	$ 2.78	$ 2.42	8.3	14.9
Dividends paid per share	$ 2.66	$ 2.66	$ 2.66	--	--

==

Earnings for 1994 increased significantly from $2.78 per share in 1993 to $3.01 per share in 1994. This improvement in earnings occurred despite the order in February 1994 from the Oklahoma Corporation Commission (the "Commission"), which effectively reduced OG&E's rates to its Oklahoma customers by approximately $17 million annually. The Commission's order also required OG&E to refund $41.3 million to its customers. The refund had only a slight impact on 1994 results as approximately $39.1 million of the refund had been recorded in 1993 and 1992.

In 1994, the Company restructured and redesigned its operations to reduce costs in order to more favorably position itself for the competitive electric utility environment. As part of this process, the Company implemented a Voluntary Early Retirement Package ("VERP") and a severance package in 1994. Those two programs reduced the Company's workforce by more than 900 employees.

In the third quarter of 1994, OG&E deferred the costs associated with the VERP and severance package, pending a Commission order. Labor savings in 1994 approximated the amortization of the deferred amount and therefore, did not significantly impact 1994 results. However, approximately $6.5 million in other restructuring expenses reduced 1994 earnings by $0.10 per share. At December 31, 1994, the deferred amount was $48.9 million, which is included on the Consolidated Balance Sheets as Deferred Charges - Other. In response to an application filed by OG&E on August 9, 1994, the Commission issued an order on October 26, 1994, that permitted the Company to amortize the December 31, 1994, balance of the regulatory asset over 26 months and reduced OG&E's electric rates by approximately $15 million annually, effective January 1995. In 1995 and 1996, the labor savings are expected to substantially offset the amortization of the regulatory asset and the annual rate reduction of $15 million. See Note 10 of Notes to Consolidated Financial Statements for a further discussion of the Commission's orders in February and October 1994.

The dividend payout ratio (expressed as a percentage of earnings available for common) improved in 1994 to 88 percent as compared to 96 percent for 1993. The Company's long-term goal is to achieve a dividend payout ratio of 75 percent based on long-term earnings expectations.

The following discussion and analysis presents factors which had a material effect on the Company's operations and financial position 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.

EARNINGS

In 1994, earnings per share increased $0.23, or 8.3 percent from those reported in 1993. The increase resulted primarily from increased retail electric kilowatt-hour sales in 1994 and less impact than in 1993 from the Commission's February 1994 rate order. The 1993 increase in earnings was attributable almost in its entirety to increased retail electric sales from more normal weather in the Company's service territory, which more than offset the provision for rate refund recorded in 1993 ($0.32 per share) related to the Commission's refund order in February 1994.

RESULTS OF OPERATIONS

REVENUES				PERCENT CHANGE FROM PRIOR YEAR	
(THOUSANDS)	1994	1993	1992	1994	1993

Sales of electricity to OG&E customers	$ 1,188,550	$ 1,242,964	$ 1,149,894	(4.4)	8.1
Provision for rate refund	(3,417)	(14,963)	(18,000)	*	*
Sales of electricity to other utilities	11,765	54,815	62,099	(78.5)	(11.7)
Enogex	158,270	164,436	120,991	(3.7)	35.9
Total operating revenues	$ 1,355,168	$ 1,447,252	$ 1,314,984	(6.4)	10.1
System kilowatt-hour sales	20,642,675	20,201,533	19,236,843	2.2	5.0
Kilowatt-hour sales to other utilities	556,765	3,103,977	4,141,084	(82.1)	(25.0)
Total kilowatt-hour sales	21,199,440	23,305,510	23,377,927	(9.0)	(0.3)

* Not meaningful

In 1994, approximately 88 percent of the Company's revenues consisted of regulated sales of electricity as a public utility, while the remaining 12 percent was provided by the non-utility operations of the Company's wholly-owned subsidiary, Enogex Inc. and its subsidiaries (collectively "Enogex"). Revenues from sales of electricity are somewhat seasonal, with a large portion of the Company's annual electric revenues being derived during the summer months when the electricity needs of its customers increase. Enogex's primary operations consist of transporting natural gas through its intra-state pipeline to various customers (including OG&E), buying and selling natural gas to third parties, selling natural gas liquids extracted by its natural gas processing plants and investing in natural gas exploration and production activities. 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.

Overall, 1994 operating revenues decreased $92.1 million, or 6.4 percent, primarily due to recovery of substantially reduced fuel costs, a significant reduction in kilowatt-hour sales to other utilities, milder weather and lower revenue from Enogex businesses. Partially offsetting the impact of these reductions was a 2.2 percent growth in kilowatt-hour sales to OG&E customers ("system sales"). The 1994 rate reduction did not significantly affect 1994 revenues when compared to 1993, due to the increased system sales in 1994, and since 1993 revenues reflected a $15 million provision for rate refund.

Enogex revenues decreased 3.7 percent in 1994. Primary factors for the decreases were lower natural gas prices, slightly lower volumes of natural gas sold by Enogex and lower transportation fees on gas transported for OG&E. These decreases were only partially offset by increased sales of natural gas liquids.

During 1993, operating revenues increased $132.3 million or 10.1 percent compared to 1992. Increased system sales, the recovery of higher purchased power costs and Enogex accounted for the increased revenues. These increases were only partially offset by the Commission's rate order in February 1994, which reduced 1993 operating revenues by approximately $15 million.

A return to near normal weather and continued slight customer growth contributed to the increase in system sales for 1993. This increase in system sales was partially offset by a 25.0 percent decrease in sales to other utilities; causing total kilowatt-hour sales to be down by 0.3 percent for 1993. However, sales to other utilities are at much lower prices per kilowatt-hour and have less impact on operating revenues and income than system sales.

Enogex's 1993 revenues increased due to higher prices on natural gas sales and increased sales of petroleum products.

EXPENSES AND OTHER ITEMS

(DOLLARS IN THOUSANDS)	1994	1993	1992	PERCENT CHANGE FROM PRIOR YEAR 1994	1993
Fuel	$ 263,329	$ 383,207	$ 377,575	(31.3)	1.5
Purchased power	228,701	218,689	182,230	4.6	20.0
Gas purchased for resale (Enogex)	114,044	140,311	97,486	(18.7)	43.9
Other operation and maintenance .	284,194	274,988	266,061	3.3	3.4
Restructuring	21,035	--	--	*	*
Depreciation	126,377	119,543	110,700	5.7	8.0
Taxes	117,022	115,361	103,928	1.4	11.0
Total operating expenses . . .	$1,154,702	$1,252,099	$1,137,980	(7.8)	10.0

* Not meaningful

Total operating expenses decreased $97.4 million, or 7.8 percent in 1994, due to reduced fuel costs for the production of electricity and decreases in both quantities and prices of gas purchased for resale by Enogex. These reductions were partially offset by the cost of restructuring and increases in purchased power and depreciation.

The Company's generating capability is almost evenly divided between coal and natural gas and provides the flexibility to use either fuel to the best economic advantage for the Company and its customers. During 1994, fuel costs decreased approximately $120.0 million, or 31.3 percent, due to renegotiated coal and transportation contracts, lower natural gas usage and a 15.9 percent reduction in the volume of kilowatt-hours generated (due to economic purchases of power from other utilities and a reduction in sales to other utilities). In 1993, fuel expense increased approximately $5.6 million, or 1.5 percent, primarily due to increased prices of gas used in the generation of electricity, which more than offset a 3.5 percent reduction in consumption of natural gas used to generate electricity.

Purchased power costs amounted to $228.7 million in 1994, up from $218.7 million and $182.2 million, in 1993 and 1992, respectively. The $10.0 million increase in 1994 resulted from economic purchases of power from other utilities, while the $36.5 million increase in 1993 resulted from price escalation provisions contained in certain cogeneration contracts. As required by the Public Utility Regulatory Policy Act of 1978 ("PURPA"), the Company must currently purchase power from qualified cogeneration facilities. In 1998, another qualified cogeneration facility is scheduled to become operational and the Company is obligated to purchase up to 100 megawatts of capacity from this facility as well. See related discussion of purchased power in Note 9 of Notes to Consolidated Financial Statements.

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 Commission, the Arkansas Public Service Commission and the Federal Energy Regulatory Commission ("FERC").

Even though increases and decreases are passed through to customers, in 1993 the Company began utilizing a natural gas storage facility which helps OG&E lower fuel costs and receive greater value from its remaining take-or-pay gas contracts. By diverting natural gas into storage, OG&E is able to use as much coal as possible to generate electricity, and use gas from storage when needed to meet increases in demand for electricity. The higher level of fuel inventories at the end of 1994 was attributable to increased usage of the natural gas storage facility and the relatively low level of fuel inventories at the end of 1993 was due to significant kilowatt-hour sales to other utilities.

The Company has initiated numerous other ongoing programs that have helped reduce the cost of generating electricity over the last several years. These programs include: 1) spot market purchases of coal; 2) renegotiated contracts for coal, gas, railcar maintenance and coal transportation; and 3) a heat rate awareness program to produce kilowatt-hours with less fuel. Reducing fuel costs helps OG&E remain competitive, which in turn helps OG&E's electric customers remain competitive in a global economy.

Enogex's gas purchased for resale decreased $26.3 million or 18.7 percent for 1994 compared to an increase of $42.8 million or 43.9 percent for 1993. The 1994 decrease was due to reduced volumes and lower natural gas prices, while the 1993 increase

resulted from higher gas prices and increased volumes compared to 1992.

Other operation and maintenance increased by approximately $9.2 million and $8.9 million in 1994 and 1993, respectively. A $5.4 million decrease in production maintenance in 1994, net of labor savings, was more than offset by: (i) expensing $8.4 million of previously deferred costs associated with Statement of Financial Accounting Standards ("SFAS") No. 106, "Employers' Accounting for Postretirement Benefits Other Than Pensions;" (ii) current recognition of SFAS No. 106 costs; and (iii) increased costs of producing natural gas liquids at Enogex. The 1993 increase in other operation and maintenance expenses resulted from major overhauls at two generating plants and increased labor costs.

The Company offered a Voluntary Early Retirement Package ("VERP") and more than 730 employees elected to retire in July, at a cost of approximately $58.5 million. The Company also incurred approximately $4.9 million of costs related to a severance package. The costs of the VERP and severance package were deferred, pending a Commission order. Between August 1, and December 31, 1994, the amount deferred was reduced by approximately $14.5 million, which is the approximate amount of labor savings during that same period. In response to an application filed by the Company, the Commission issued an order in October 1994 approving the Company's proposed accounting treatment of certain restructuring costs. At December 31, 1994, the unamortized balance of the regulatory asset was $48.9 million, which is included on the Consolidated Balance Sheets as Deferred Charges - Other. This regulatory asset will be amortized over 26 months, as permitted by the Commission's order. Restructuring expenses, which resulted from a complete review and redesign of the Company's operations, were approximately $21.0 million in 1994 (including amortization of the deferred charge). Restructuring expenses included only costs that were actually incurred in 1994. See Note 7 of Notes to Consolidated Financial Statements.

The increases in depreciation for 1994 and 1993 reflect higher levels of depreciable plant. Also, the adoption of SFAS No. 109, "Accounting for Income Taxes," during 1993 and its effect on Enogex contributed to the increase in depreciation. See Note 2 of Notes to Consolidated Financial Statements.

In 1994, income taxes increased primarily due to higher pre-tax earnings. Income taxes during 1993 increased primarily due to higher pre-tax earnings and a one percent increase in the federal income tax rate to 35 percent.

The variances in interest expense for 1994 and 1993 were primarily attributable to the approximate $6.2 million of interest in 1993, associated with the refund ordered by the Commission in February 1994. See Note 10 of Notes to Consolidated Financial Statements.

LIQUIDITY, CAPITAL RESOURCES AND CONTINGENCIES

The primary capital requirements for 1994 and as estimated for 1995 through 1997 are as follows:

(DOLLARS IN MILLIONS)	1994	1995	1996	1997
Construction expenditures including AFUDC	$ 150	$ 89	$ 89	$ 89
Maturities of long-term debt and sinking fund requirements	--	25	--	15
Total	$ 150	$ 114	$ 89	$104

CONSTRUCTION

The Company's primary needs for capital are related to 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 and sinking fund obligations. Approximately $7.4 million of the Company's construction expenditures budgeted for 1995 are to comply with environmental laws and regulations. Because of the continuing trend toward greater environmental awareness and increasingly stringent regulation, the Company has been experiencing a trend towards increasing environmental costs. This trend has caused and may continue to cause slightly higher operating expenditures and capital expenditures for environmental matters.

The construction program for the next several years does not include any additional base-load generating units. Rather, to meet the increased electricity needs of its customers during the balance of this century, the Company will concentrate on

maintaining the reliability and increasing the utilization of existing capacity and increasing demand-side management efforts.

FINANCE

The Company meets its cash needs through internally generated funds, short-term borrowings and permanent financing. Cash flows from operations remained strong, which enabled the Company to internally generate the required funds to satisfy construction expenditures during 1994 and 1993. Management expects that internally generated funds will be adequate over the next three years to meet anticipated capital requirements. Short-term borrowings will continue to be used to meet temporary cash requirements. The maximum amount of outstanding short-term borrowings during 1994 was $220 million. The Company has the necessary regulatory approvals to incur up to $400 million in short-term borrowings at any one time.

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.

In August 1994, Enogex redeemed its $90 million of outstanding medium-term notes, with interest rates ranging from 9.88% to 10.11%. Enogex anticipates issuing long-term debt in 1995 to replace short-term borrowings in connection with such redemption.

In January 1995, OG&E refinanced its obligations with respect to $47,000,000 of 5 7/8% Pollution Control Revenue Bonds due December 1, 2007 and $32,050,000 of 6 3/4% Pollution Control Revenue Bonds due March 1, 2006 through the issuance of two new series of pollution control bonds bearing interest at variable, tax-exempt rates. These refinancings are expected to result in lower long-term interest rates during 1995.

CONTINGENCIES

The Company is defending various claims and legal actions, including environmental actions, which are common to its operations. As to environmental matters, the Company has been designated as a "potentially responsible party" ("PRP") with respect to three waste disposal sites to which the Company sent materials. Under applicable law, the Company and each PRP could be held jointly and severally liable for site remediation. Neither the amount of cleanup costs nor the final method of their allocation among all designated PRPs at any of these sites has been determined. While it is not possible to determine the precise outcome of these matters, in the opinion of management, the Company's ultimate liability for the clean-up costs of these sites will not have a material adverse effect on the Company's consolidated financial position or results of operations. Management's opinion is based on the following: 1) the clean-up costs already paid by certain parties, 2) the financial viability of the other PRPs, and 3) the portion of the total wastes disposed at the sites attributable to the Company. Management also believes that costs incurred in connection with the sites, which are not recovered from insurance carriers or other parties, may be allowable costs for future ratemaking purposes.

The Company continues to explore options to comply with the Clean Air Act Amendments of 1990 ("CAAA"). Since all of OG&E's coal-fired generating units currently burn low-sulfur coal, OG&E will not need to take any steps to comply with the new sulfur dioxide emission limits until January 1, 2000. In compliance with Title IV of the CAAA, the Company has completed installation of continuous emission monitors ("CEMs") on each of its five coal-fired generating units and three of its 12 gas-fired generating units. Expenditures on CEMs in 1994 totalled approximately $6 million. The Environmental Protection Agency ("EPA") established a time extension for installation of CEMs on gas-fired units which allowed the Company to defer CEM installation on the remaining nine units subject to the requirements of Title IV. Completion of this project is expected to cost approximately $1 million during 1995. The CAAA Title V operating permits are expected to cost approximately $400,000 in 1995.

The CAAA will also regulate emissions of nitrogen oxides and certain air toxic compounds. Although final regulations concerning all of these issues have not been written, additional capital expenditures may be necessary in future years. The Company will continue to examine all alternatives to comply with the CAAA as part of its Integrated Resource Planning process. This planning approach will assure the Company employs the least cost option to comply with the CAAA and be in a competitive position to market its services.

During 1992, OG&E disclosed to the EPA discrepancies in the 1991 annual report required by the Toxic Substance Control Act ("TSCA"). These discrepancies were administrative in nature and presented no harm to the environment and presented no health problems to our Company members or the public. However, the Company has instituted specific systems and measures to correct each of the reported discrepancies. No actions were taken by the EPA on this matter during 1994. See Note 9 of Notes to Consolidated Financial Statements for a further discussion of this matter.

In October 1992, the National Energy Policy Act of 1992 ("Energy Act") was enacted. Among many other provisions, the Energy Act is designed to promote competition in the development of wholesale power generation in the electric utility industry. It exempts a new class of independent power producers from regulation under the Public Utility Holding Company Act of 1935 and allows the FERC to order "wholesale wheeling" by public utilities to provide utility and non-utility generators access to public utility transmission facilities. Also, numerous states are considering proposals to require "retail wheeling" which is the delivery of power generated by a third party to retail customers. In 1995, the Company intends to make a transmission open access filing before the FERC, in compliance with the Energy Act, and the Company intends to implement Real Time Pricing for a pilot group of its retail customers. The Energy Act, these proposals and other factors are expected to significantly increase competition in the electric industry. The Company has taken steps in the past and intends to take appropriate steps in the future to remain a competitive supplier of electricity. Past actions include the redesign and restructuring effort in 1994 and the actions to reduce fuel costs, both of which have resulted in lower retail rates, especially for industrial customers.

Besides the existing contingencies described above and those described in Note 9 of Notes to Consolidated Financial Statements, the Company's ability to fund its future operational needs and to finance its construction program is dependent upon numerous other factors beyond its control, such as general economic conditions, abnormal weather, load growth, inflation, new environmental laws or regulations and the cost and availability of external financing.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

CONSOLIDATED STATEMENTS OF INCOME

YEAR ENDED DECEMBER 31 (DOLLARS IN THOUSANDS EXCEPT PER SHARE DATA)	1994	1993	1992
OPERATING REVENUES	$ 1,355,168	$ 1,447,252	$ 1,314,984
OPERATING EXPENSES:			
Fuel	263,329	383,207	377,575
Purchased power	228,701	218,689	182,230
Gas purchased for resale	114,044	140,311	97,486
Other operation	216,961	196,323	193,622
Maintenance	67,233	78,665	72,439
Restructuring	21,035	--	--
Depreciation	126,377	119,543	110,700
Current income taxes	50,129	72,003	61,325
Deferred income taxes, net	27,092	5,286	4,346
Deferred investment tax credits, net	(5,150)	(5,150)	(5,465)
Taxes other than income	44,951	43,222	43,722
Total operating expenses	1,154,702	1,252,099	1,137,980
OPERATING INCOME	200,466	195,153	177,004
OTHER INCOME AND DEDUCTIONS:			
Interest income	3,409	1,431	629
Other	(5,576)	(2,732)	(1,196)
Net other income and deductions	(2,167)	(1,301)	(567)
INTEREST CHARGES:			
Interest on long-term debt	67,680	70,490	71,230
Allowance for borrowed funds used during construction	(1,073)	(433)	(809)
Other	7,907	9,518	6,304
Total interest charges, net	74,514	79,575	76,725
NET INCOME	123,785	114,277	99,712
PREFERRED DIVIDEND REQUIREMENTS	2,317	2,317	2,317
EARNINGS AVAILABLE FOR COMMON	$ 121,468	$ 111,960	$ 97,395
AVERAGE COMMON SHARES OUTSTANDING (thousands)	40,344	40,328	40,310
EARNINGS PER AVERAGE COMMON SHARE	$ 3.01	$ 2.78	$ 2.42

CONSOLIDATED STATEMENTS OF RETAINED EARNINGS

YEAR ENDED DECEMBER 31 (DOLLARS IN THOUSANDS)	1994	1993	1992

BALANCE AT BEGINNING OF PERIOD	$ 395,811	$ 391,135	$ 400,976
ADD--net income	123,785	114,277	99,712
Total	519,596	505,412	500,688
DEDUCT:			
Cash dividends declared on preferred stock	2,317	2,317	2,317
Cash dividends declared on common stock	107,319	107,284	107,236
Total	109,636	109,601	109,553
BALANCE AT END OF PERIOD	$ 409,960	$ 395,811	$ 391,135

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

CONSOLIDATED BALANCE SHEETS

DECEMBER 31 (DOLLARS IN THOUSANDS)	1994	1993	1992
ASSETS			
PROPERTY, PLANT AND EQUIPMENT:			
In service	$ 3,770,247	$ 3,656,113	$ 3,471,588
Construction work in progress	43,943	33,970	37,147
Total property, plant and equipment	3,814,190	3,690,083	3,508,735
Less accumulated depreciation	1,487,300	1,370,227	1,267,472
Net property, plant and equipment	2,326,890	2,319,856	2,241,263
OTHER PROPERTY AND INVESTMENTS, at cost	7,868	6,920	6,269
CURRENT ASSETS:			
Cash and cash equivalents	2,455	6,593	11,316
Accounts receivable--customers, less reserve of $3,719, $4,070 and $4,039, respectively	118,318	126,997	107,805
Accrued unbilled revenues	36,800	45,100	45,300
Accounts receivable--other	8,601	6,269	6,378
Fuel inventories, at LIFO cost	46,494	27,127	37,066
Materials and supplies, at average cost	30,401	26,813	24,614
Prepayments and other	43,137	28,648	5,215
Accumulated deferred tax asset	12,077	24,088	--
Total current assets	298,283	291,635	237,694
DEFERRED CHARGES:			
Advance payments for gas	10,000	21,165	22,743
Income taxes recoverable through future rates	47,246	47,593	44,387
Other	92,342	44,255	37,727
Total deferred charges	149,588	113,013	104,857
TOTAL ASSETS	$ 2,782,629	$ 2,731,424	$ 2,590,083

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

DECEMBER 31 (DOLLARS IN THOUSANDS)	1994	1993	1992
CAPITALIZATION AND LIABILITIES			

CAPITALIZATION (see statements):			
Common stock and retained earnings	$ 921,177	$ 906,804	$ 901,503
Cumulative preferred stock	49,973	49,973	49,973
Long-term debt	730,567	838,660	838,654
Total capitalization	1,701,717	1,795,437	1,790,130
CURRENT LIABILITIES:			
Short-term debt	182,750	47,000	26,000
Accounts payable	66,391	100,285	94,549
Dividends payable	27,415	27,410	27,397
Customers' deposits	20,904	19,353	17,891
Accrued taxes	25,153	24,717	27,169
Accrued interest	23,873	26,712	29,961
Long-term debt due within one year	25,350	350	15,300
Accumulated provision for rate refund	2,970	39,117	--
Other	41,321	48,666	45,541
Total current liabilities	416,127	333,610	283,808
DEFERRED CREDITS AND OTHER LIABILITIES:			
Accrued pension and benefit obligation	71,014	16,210	5,620
Accumulated provision for rate refund	--	--	18,000
Accumulated deferred income taxes	497,056	484,003	384,114
Accumulated deferred investment tax credits	88,328	93,478	98,627
Other	8,387	8,686	9,784
Total deferred credits and other liabilities	664,785	602,377	516,145
COMMITMENTS AND CONTINGENCIES (NOTES 9 AND 10)			
TOTAL CAPITALIZATION AND LIABILITIES	$ 2,782,629	$ 2,731,424	$ 2,590,083

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

CONSOLIDATED STATEMENTS OF CAPITALIZATION

DECEMBER 31 (DOLLARS IN THOUSANDS)		1994	1993	1992
COMMON STOCK AND RETAINED EARNINGS:				
Common stock, par value $2.50 per share; Authorized 100,000,000 shares; issued 46,470,616 shares		$ 116,177	$ 116,177	$ 116,177
Premium on capital stock		608,158	608,195	608,174
Retained earnings		409,960	395,811	391,135
Treasury stock--6,116,229, 6,124,139 and 6,141,591 shares, respectively		(213,118)	(213,379)	(213,983)
Total common stock and retained earnings		921,177	906,804	901,503
CUMULATIVE PREFERRED STOCK:				
Par value $20, authorized 675,000 shares--4%; outstanding 423,663 shares		8,473	8,473	8,473
Par value $25, authorized and unissued 4,000,000 shares		--	--	--
Par value $100, authorized 1,865,000 shares--				
SERIES	SHARES OUTSTANDING			
4.20%	50,000	5,000	5,000	5,000
4.24%	75,000	7,500	7,500	7,500
4.44%	65,000	6,500	6,500	6,500
4.80%	75,000	7,500	7,500	7,500
5.34%	150,000	15,000	15,000	15,000
Total cumulative preferred stock		49,973	49,973	49,973
LONG-TERM DEBT:				
First mortgage bonds--				
SERIES	DATE DUE			
4 1/4%	March 1, 1993	--	--	15,000
4 1/2%	March 1, 1995	25,000	25,000	25,000
5 1/8%	January 1, 1997	15,000	15,000	15,000
6 3/8%	January 1, 1998	25,000	25,000	25,000
7 1/8%	January 1, 1999	12,500	12,500	12,500
8 5/8%	January 1, 2000	30,000	30,000	30,000
7 1/8%	January 1, 2002	40,000	40,000	40,000
8 3/8%	January 1, 2004	75,000	75,000	75,000
9 1/8%	January 1, 2005	60,000	60,000	60,000
8 5/8%	January 1, 2006	55,000	55,000	55,000
8 3/8%	January 1, 2007	75,000	75,000	75,000
8 5/8%	November 1, 2007	35,000	35,000	35,000

8 1/4%	August 15, 2016	100,000	100,000	100,000
8 7/8%	December 1, 2020	75,000	75,000	75,000
5 7/8%	Pollution Control Series A, December 1, 2007	47,000	47,000	47,000
7%	Pollution Control Series C, March 1, 2017	56,000	56,000	56,000
Other bonds--				
6 3/4%	Muskogee Industrial Trust Bonds, March 1, 2006	32,050	32,400	32,700
Unamortized premium and discount, net		(8,533)	(8,890)	(9,246)
Enogex Inc. notes		6,900	90,000	90,000
Total long-term debt		755,917	839,010	853,954
Less long-term debt due within one year		25,350	350	15,300
Total long-term debt (excluding long-term debt due within one year)		730,567	838,660	838,654
Total Capitalization		$ 1,701,717	$ 1,795,437	$ 1,790,130

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

CONSOLIDATED STATEMENTS OF CASH FLOWS

YEAR ENDED DECEMBER 31 (DOLLARS IN THOUSANDS)	1994	1993	1992
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net Income	$ 123,785	$ 114,277	$ 99,712
Adjustments to Reconcile Net Income to Net Cash Provided from Operating Activities:			
Depreciation	126,377	119,543	110,700
Deferred income taxes and investment tax credits, net	21,942	136	(1,119)
Provision for rate refund	4,200	21,117	18,000
Change in Certain Current Assets and Liabilities:			
Accounts receivable--customers	8,679	(19,192)	1,803
Accrued unbilled revenues	8,300	200	(12,500)
Fuel, materials and supplies inventories	(22,955)	7,740	5,473
Accumulated deferred tax assets	12,011	(24,088)	--
Other current assets	(16,821)	(23,324)	(762)
Accounts payable	(35,667)	5,268	6,220
Accrued taxes	436	(2,452)	(7,331)
Accrued interest	(2,839)	(3,249)	4,537
Accumulated provision for rate refund	(36,147)	39,117	--
Other current liabilities	(5,789)	4,600	4,433
Other operating activities	18,698	(12,841)	12,863
Net cash provided from operating activities	204,210	226,852	242,029
CASH FLOWS FROM INVESTING ACTIVITIES:			
Capital expenditures	(151,012)	(127,674)	(141,936)
Net cash used in investing activities	(151,012)	(127,674)	(141,936)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Retirement of long-term debt	(83,450)	(15,300)	(300)
Short-term debt	135,750	21,000	13,500
Cash dividends declared on preferred stock	(2,317)	(2,317)	(2,317)
Cash dividends declared on common stock	(107,319)	(107,284)	(107,236)
Net cash used in financing activities	(57,336)	(103,901)	(96,353)
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	(4,138)	(4,723)	3,740
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	6,593	11,316	7,576
CASH AND CASH EQUIVALENTS AT END OF PERIOD	$ 2,455	$ 6,593	$ 11,316
SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION			
Cash Paid During the Period for:			
Interest (net of amount capitalized)	$ 74,372	$ 71,401	$ 73,691
Income taxes	$ 57,416	$ 79,953	$ 60,229

DISCLOSURE OF ACCOUNTING POLICY:

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

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

PRINCIPLES OF CONSOLIDATION

The consolidated financial statements include the accounts of Oklahoma Gas and Electric Company ("OG&E"), its wholly-owned non-utility subsidiary Enogex Inc. and its subsidiaries ("Enogex") (collectively, the "Company"). All significant intercompany transactions have been eliminated in consolidation.

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 (the "Oklahoma Commission") and the Arkansas Public Service Commission (the "Arkansas Commission"). Additionally, OG&E is subject to the accounting principles prescribed by Statement of Financial Accounting Standards ("SFAS") No. 71, "Accounting for the Effects of Certain Types of Regulation." SFAS No. 71 provides that, based upon the expectation to recover from, or flowback to, future customers, certain costs can be deferred as regulatory assets, rather than expensed and certain credits can be recognized as regulatory liabilities, rather than treated as income. Management's expected recovery of deferred costs and flowback of deferred credits generally results from specific decisions by regulators granting such ratemaking treatment. 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. See Notes 7 and 10 of Notes to Consolidated Financial Statements for related discussion.

PROPERTY, PLANT AND EQUIPMENT

All property, plant and equipment is recorded at cost. Electric utility plant is recorded at its original cost. Newly constructed plant is added to plant balances at costs which include contracted services, direct labor, materials, overhead and allowance for funds used during construction. Replacement of major units of property are capitalized as plant. The replaced plant is removed from plant balances and the cost of such property together with the cost of removal less salvage is charged to accumulated depreciation. Repair and replacement of minor items of property are included in the Consolidated Statements of Income as maintenance expense.

DEPRECIATION

The provision for depreciation, which was approximately 3.2% of the average depreciable utility plant, for each of the years 1994, 1993 and 1992, is provided on a straight-line method over the estimated service life of the property. Depreciation is provided at the unit level for production plant and at the account or sub-account level for all other plant, and is based on the average life group procedure.

Enogex's gas pipeline and gas processing plants are depreciated on a straight-line method over a period of 20 to 48 years.

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 4.58%, 3.60% and 4.30% for the years 1994, 1993 and 1992, respectively.

UNBILLED REVENUE

OG&E accrues estimated revenues for services provided but not yet billed. The cost of providing service is recognized as incurred.

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 estimated cost-of-service for ratemaking, are charged to substantially all of the Company's electric customers through automatic fuel adjustment clauses, which are subject to periodic review by the Oklahoma Commission, the Arkansas Commission and the FERC.

FUEL INVENTORIES

Fuel inventories for the generation of electricity consist of coal, oil and natural gas. These inventories are accounted for under the last-in, first-out ("LIFO") cost method. The estimated replacement cost of fuel inventories exceeded the stated LIFO cost by approximately $2.5 million, $2.3 million and $4.8 million for 1994, 1993 and 1992, respectively, based on the average cost of fuel purchased late in the respective years. LIFO liquidation gains and losses (no gains or losses in 1994, approximately $0.5 million gain in 1993 and approximately $1.3 million loss in 1992) reduced or increased the Company's recovery under its automatic fuel adjustment clauses, with no impact on net income. Natural gas products inventories are held for sale and accounted for based on the weighted average cost of production.

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2. INCOME TAXES

The items comprising tax expense are as follows:

YEAR ENDED DECEMBER 31 (DOLLARS IN THOUSANDS)	1994	1993	1992
Current Income Taxes			
Provision for current taxes:			
Federal	$ 42,974	$ 61,406	$ 52,191
State	7,155	10,597	9,134
Total Current Income Taxes	50,129	72,003	61,325
Deferred Income Taxes, net			
Provision (benefit) for deferred taxes:			
Federal			
Depreciation	7,372	9,673	6,185
Repair allowance	1,109	1,360	1,908
Removal costs	1,542	1,026	635
Provision for rate refund	12,406	(6,972)	(5,774)
Other	812	(225)	1,059
State	3,851	424	333
Total Deferred Income Taxes, net	27,092	5,286	4,346
Deferred Investment Tax Credits, net	(5,150)	(5,150)	(5,465)
Income Taxes Relating to Other Income and Deductions	203	(538)	(1,006)
Total Income Tax Expense	$ 72,274	$ 71,601	$ 59,200
Pretax Income	$ 196,059	$ 185,878	$ 158,912

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

YEAR ENDED DECEMBER 31	1994	1993	1992
Statutory federal tax rate	35.0%	35.0%	34.0%
State income taxes, net of federal income tax benefit	3.7	3.9	3.9
Investment tax credits, net	(2.6)	(2.8)	(3.4)
Change in federal tax rate	--	0.9	--
Other, net	0.8	1.5	2.8
Effective income tax rate as reported	36.9%	38.5%	37.3%

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.

Payment of the rate refund in 1994 resulted in lower current income tax expense. The provisions for rate refund accrued in 1992 and 1993 were not deductible for income tax purposes until the refund was paid in 1994, resulting in higher current income tax expense in 1992 and 1993.

The Company follows the provisions of SFAS No. 109, "Accounting for Income Taxes," which it adopted effective January 1, 1993. SFAS No. 109 requires 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 Company elected not to restate the financial statements for years ending before January 1, 1993. When adopted, SFAS No. 109 had no effect on net income.

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 are as follows:

(DOLLARS IN THOUSANDS)	DEC 31, 1994	DEC 31, 1993	JAN 1, 1993
Current Deferred Tax Assets:			
Accrued vacation	$ 3,363	$ 4,177	$ 3,359
Postemployment medical and life insurance benefits	3,235	--	--
Provision for rate refund	375	14,965	--
Uncollectible accounts	3,801	4,946	3,669
Customer deposits	--	--	1,102
Other	1,303	--	--
Accumulated deferred tax assets	$ 12,077	$ 24,088	$ 8,130
Deferred Tax Liabilities:			
Accelerated depreciation and other property-related differences	$ 455,943	$ 439,253	$ 438,419
Allowance for funds used during construction	53,317	57,074	61,346
Income taxes recoverable through future rates	58,470	62,441	61,829
Total	567,730	558,768	561,594
Deferred Tax Assets:			
Deferred investment tax credits	(28,868)	(30,616)	(32,850)
Income taxes refundable through future rates	(40,186)	(44,022)	(49,100)
Provision for rate refund	--	--	(7,074)
Other	(1,620)	(127)	(411)
Total	(70,674)	(74,765)	(89,435)
Accumulated Deferred Income Tax Liabilities	$ 497,056	$ 484,003	$ 472,159

The effect of adopting SFAS No. 109 at January 1, 1993, before adjusting for the new tax rate, resulted in a net increase in property, plant and equipment of approximately $73.9 million, a net decrease in income taxes recoverable through future rates of approximately $12.0 million and a net increase in accumulated deferred income taxes of approximately $61.9 million. Also at January 1, 1993, approximately $8.1 million of deferred tax assets which were previously netted with accumulated deferred income taxes, were reclassified as current assets as a result of adopting SFAS No. 109.

At December 31, 1992, the Company had recorded $44.4 million as unfunded deferred income taxes recoverable from customers. A corresponding amount was reflected as a component of accumulated deferred income taxes which represented amounts refundable to customers. As a result of the adoption of SFAS No. 109, the $44.4 million amount that was recorded as a component of accumulated deferred income taxes at December 31, 1992, was reclassified January 1, 1993, as a regulatory liability and netted against the regulatory asset. This reclassification combined with the $12.0 million net decrease in income taxes recoverable through future rates discussed above, resulted in a $32.4 million net increase in the amount recognized as income taxes to be recovered through future rates.

The Omnibus Reconciliation Act of 1993, signed into law on August 10, 1993, increased the top federal corporate tax rate from 34 to 35 percent. The 35 percent rate was retroactively made effective January 1, 1993.

For the temporary differences that existed at January 1, 1993, the change in the federal income tax rate increased the provision for income taxes and accumulated deferred income taxes approximately $1.6 and $18.0 million, respectively. Approximately $16.4 million of the increase which was applicable to utility operations was recorded as income taxes recoverable from customers through future rates and therefore had no impact on results of operations for the year ended December 31, 1993.

For 1992, the provision for deferred income taxes was recorded primarily as a result of the use of income tax law provisions which allowed for the deduction or addition of items to taxable income in the tax return prior to or after their being recorded on the books of the Company.

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3. COMMON STOCK AND RETAINED EARNINGS

There were no new shares of common stock issued during 1994, 1993 or 1992. The $37,000 decrease in 1994 and $21,000 increase in 1993 in premium on capital stock, as presented on the Consolidated Statements of Capitalization, represents the gains and losses associated with the issuance of common stock pursuant to the Restricted Stock Plan.

RESTRICTED STOCK PLAN

The Company has a Restricted Stock Plan whereby certain employees may periodically receive shares of the Company's common stock at the discretion of the Board of Directors. The Company distributed 18,950, 18,687 and 18,631 shares of common stock during 1994, 1993 and 1992, respectively. The Company also reacquired 11,040 and 1,235 shares in 1994 and 1993, respectively. The shares distributed/reacquired in the reported periods were recorded as treasury stock.

Changes in common stock were:

(THOUSANDS)	1994	1993	1992
Shares outstanding January 1	40,346	40,329	40,310
Issued/reacquired under the Restricted Stock Plan, net	8	17	19
Shares outstanding December 31	40,354	40,346	40,329

There were 4,009,021 shares of unissued common stock reserved for the various employee and Company stock plans at December 31, 1994. With the exception of the Restricted Stock Plan, the common stock requirements, pursuant to those plans, are currently being satisfied with stock purchased on the open market.

The Company's Restated Certificate of Incorporation and its Trust Indenture, as supplemented, relating to the First Mortgage Bonds, contained provisions which, under specific conditions, limit the amount of dividends (other than in shares of common stock) and/or other distributions which may be made to common shareowners.

In December 1991, holders of the Company's First Mortgage Bonds approved a series of amendments to the Company's Trust Indenture. The amendments eliminated the cumulative amount of the previous restrictions on retained earnings related to the payment of dividends and provided management with the flexibility to repurchase its common stock, when appropriate, in order to maintain desired capitalization ratios and to achieve other business needs. The Company is amortizing approximately $14.0 million of costs relating to obtaining such amendments over the remaining life of the respective bond issues. At the end of 1994, there was approximately $10.4 million in unamortized costs associated with obtaining these amendments.

SHAREOWNERS RIGHTS PLAN

In December 1990, the Company adopted a Shareowners Rights Plan designed to protect shareowners' interests in the event that the Company is ever confronted with an unfair or inadequate acquisition proposal. Pursuant to the plan, the Company declared a dividend distribution of one "right" for each share of Company common stock. Each right entitles the holder to purchase from the Company one one-hundredth of a share of new preferred stock of the Company under certain circumstances. The rights may be exercised if a person or group announces its intention to acquire, or does acquire, 20 percent or more of the Company's common stock. Under certain circumstances, the holders of the rights will be entitled to purchase either shares of common stock of the Company or common stock of the acquirer at a reduced percentage of market value. The rights will expire on December 11, 2000.

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4. CUMULATIVE PREFERRED STOCK

Preferred stock is redeemable at the option of OG&E at the following amounts per share plus accrued dividends: the 4% Cumulative Preferred Stock at the par value of $20 per share; the Cumulative Preferred Stock, par value $100 per share, as follows: 4.20% series-$102; 4.24% series-$102.875; 4.44% series-$102; 4.80% series-$102; and 5.34% series-$101.

As approved by shareowners on May 16, 1991, the Restated Certificate of Incorporation was amended to permit the issuance of new series of preferred stock with dividends payable other than quarterly.

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5. LONG-TERM DEBT

OG&E's Trust Indenture, as supplemented, relating to the First Mortgage Bonds, requires OG&E to pay to the trustee annually, an amount sufficient to redeem, for sinking fund purposes, 1 1/4% of the highest amount outstanding at any time. This requirement has been satisfied by pledging permanent additions to property to the extent of 166 2/3% of principal amounts of bonds otherwise required to be redeemed. Through December 31, 1994, gross property additions pledged totaled approximately $355 million.

Annual sinking fund requirements for each of the five years subsequent to December 31, 1994, are as follows:

Year	Amount
1995	$ 14,593,750
1996	$ 14,593,750
1997	$ 14,281,250
1998	$ 13,760,417
1999	$ 13,500,000

As in prior years, OG&E expects to meet these requirements by pledging permanent additions to property.

In January 1995, OG&E refinanced its obligations with respect to $47,000,000 of 5 7/8% Pollution Control Revenue Bonds due December 1, 2007 and $32,050,000 of 6 3/4% Pollution Control Revenue Bonds due March 1, 2006 through the issuance of two new series of pollution control bonds bearing interest at variable, tax-exempt rates and are due January 1, 2025. The 5 7/8% Series and the 6 3/4% Series Bonds will be called March 1, 1995.

In August 1994, Enogex redeemed its $90 million of outstanding medium-term notes, with interest rates ranging from 9.88% to 10.11%. As of December 31, 1994, Enogex long-term debt consisted of a $6.9 million, variable interest rate note, maturing July 31, 2001. At December 31, 1994, the interest rate was 8 1/4%.

Maturities of First Mortgage Bonds during the next five years consist of $25 million in 1995, $15 million in 1997, $25 million in 1998 and $12.5 million in 1999.

Unamortized debt expense and unamortized premium and discount on long-term debt are being amortized over the life of the respective debt.

Substantially all electric plant was subject to lien of the Trust Indenture at December 31, 1994.

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6. 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 1994 were $220.0 million and $130.6 million, respectively, at a weighted average interest rate of 4.76%. The weighted average interest rates for 1993 and 1992 were 3.60% and 4.30%, respectively. OG&E has an agreement for a flexible line of credit, up to $200 million, through December 31, 1997. The line of credit which was nominated by OG&E at $160 million at year-end is maintained on a fee basis of 1/8 of 1%, per year, on the unused balance. Enogex has a line of credit, up to $90 million, through July 31, 1995. The Enogex line of credit is maintained on a fee basis of LIBOR plus 1/2 of 1%, and a facility fee of 1/8 of 1% per year. Short-term debt in the amount of $182.8 million was outstanding at December 31, 1994, of which approximately $90 million pertained to debt incurred in connection with Enogex's refinancing of its medium-term notes.

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7. POSTEMPLOYMENT BENEFIT PLANS

During 1994, the Company restructured its operations, reducing its workforce by approximately 24 percent. This was accomplished through a Voluntary Early Retirement Package ("VERP") and an enhanced severance package. The VERP included enhanced pension benefits as well as postemployment medical and life insurance benefits.

As a result of the postemployment benefits provided in connection with this workforce reduction, the Company incurred severance costs and certain one-time costs computed in accordance with SFAS No. 88, "Employers' Accounting for Settlements and Curtailments of Defined Benefit Pension Plans and for Termination Benefits" and SFAS No. 106, "Employers' Accounting for Postretirement Benefits Other Than Pensions." In response to an application filed by the Company, the Oklahoma Commission directed the Company to defer the one-time costs which had not been offset by labor savings through December 31, 1994. The remaining balance of the one-time costs will be amortized over 26 months. The components of the severance and VERP costs and the amount deferred are as follows:

(DOLLARS IN THOUSANDS)	SFAS NO. 88	SFAS NO. 106	SEVERANCE	TOTAL
Curtailment Loss	$ 1,042	$ 5,457	$ --	$ 6,499
Recognition of Transition Obligation	--	17,268	--	17,268
Special Retirement Benefits	28,198	6,566	--	34,764
Enhanced Severance	--	--	4,891	4,891
Total VERP and Severance Costs	$ 29,240	$ 29,291	$ 4,891	63,422
Deferred as a Regulatory Asset				(48,903)
Postemployment Costs Recognized as Restructuring in 1994				14,519
Consulting Fees				2,750
Other				3,766
1994 Restructuring Expenses				$ 21,035

The restructuring charges reflected above, include only costs that were actually incurred in 1994.

PENSION PLAN

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

It is the Company's policy to fund the plan on a current basis to comply with the minimum required contributions under existing tax regulations. 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.

Net periodic pension cost is computed in accordance with provisions of SFAS No. 87, "Employers' Accounting for Pensions," and is recorded in the accompanying Consolidated Statements of Income as Other operation.

In determining the projected benefit obligation, the weighted average discount rate used was 8.25%, 7.25% and 8.5% for 1994, 1993 and 1992, respectively. The assumed rate of increase in future salary levels was 4.5% in 1994 and 1993 and 5.5% in 1992. The expected long-term rate of return on assets used in determining net periodic pension cost was 9.0% for the reported periods.

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

Net periodic pension costs for 1994, 1993 and 1992 included the following:

(DOLLARS IN THOUSANDS)	1994	1993	1992
Service costs-benefits earned during year	$ 7,824	$ 7,630	$ 7,266
Interest cost on projected benefit obligation	17,851	14,557	13,657
Return on plan assets	(17,510)	(15,697)	(14,761)
Net amortization and deferral	(1,263)	(1,263)	(1,263)
Amortization of unrecognized prior service cost	1,489	671	671
Net periodic pension cost	$ 8,391	$ 5,898	$ 5,570

The following table sets forth the plan's funded status at December 31, 1994, 1993 and 1992:

(DOLLARS IN THOUSANDS)	1994	1993	1992
Projected benefit obligation:			
Vested benefits	$(208,438)	$(140,958)	$(113,072)
Nonvested benefits	(14,664)	(21,435)	(17,709)
Accumulated benefit obligation	(223,102)	(162,393)	(130,781)
Effect of future compensation levels	(29,425)	(51,196)	(47,632)
Projected benefit obligation	(252,527)	(213,589)	(178,413)
Plan's assets at fair value	177,045	194,501	176,891
Plan's assets less than projected benefit obligation . .	(75,482)	(19,088)	(1,522)
Unrecognized prior service cost	43,250	7,942	8,613
Unrecognized net asset from application of SFAS No. 87 .	(8,842)	(10,106)	(11,369)
Unrecognized net (gain) loss	(900)	14,448	281
Accrued pension liability	$ (41,974)	$ (6,804)	$ (3,997)

POSTRETIREMENT MEDICAL AND LIFE INSURANCE BENEFITS

In addition to providing pension benefits, the Company provides certain medical and life insurance benefits for retired members ("postretirement benefits"). Employees retiring from the Company on or after attaining age 55 who have met certain length of service requirements are entitled to these benefits. The benefits are subject to deductibles, co-payment provisions and other limitations. Prior to January 1, 1993, the costs of retiree medical and life insurance benefits were recognized as expense when claims were paid ("pay-as-you-go"). Pay-as-you-go costs totaled approximately $4,621,000, $3,804,000 and $3,443,000 for 1994, 1993 and 1992, respectively.

The Company adopted the provisions of SFAS No. 106 beginning January 1, 1993. This standard requires that employers accrue the cost of postretirement benefits during the active service periods of employees until the date they attain full eligibility for the benefits.

During 1993, OG&E expensed "pay-as-you-go" postretirement benefits and recorded a deferral for the difference between pay-as-you-go and SFAS No. 106 requirements. The February 25, 1994, Oklahoma Commission rate order directed OG&E to recover postretirement benefit costs following the pay-as-you-go method and to defer the incremental cost associated with accrual recognition of SFAS No. 106 related costs following a "phase-in" plan. Accordingly, OG&E recorded a regulatory asset for the difference between the amounts using the pay-as-you-go method (adjusted for the phase-in plan) and those required by SFAS No. 106.

A decision was made in the second quarter of 1994 to discontinue deferral of the differential and to charge to expense $8.4 million of postretirement benefits that had been recorded as a regulatory asset. Although OG&E continues to believe that it could have recovered these costs in future rate proceedings before the Oklahoma Commission, OG&E decided to recognize these expenses currently, due to its strategy to reduce its cost-structure, which minimizes future revenue requirements. OG&E expects to continue charging to expense the SFAS No. 106 costs and to include an annual amount as a component of cost-of-service in future ratemaking proceedings.

Net postretirement benefit expense for the years ended December 31, 1994 and December 31, 1993, included the following components:

(DOLLARS IN THOUSANDS)	1994	1993
Service cost.	$ 2,714	$ 2,812
Interest cost	5,978	6,158
Net amortization	3,549	3,687
Net amount capitalized or deferred	(4,557)	(8,853)
Discontinued deferral of regulatory asset	8,359	--
Net postretirement benefit expense	$ 16,043	$ 3,804

The discount rate used in determining the accumulated postretirement benefit obligation was 8.25%, 7.25% and 8.5% for December 31, 1994, December 31, 1993 and January 1, 1993, respectively. The rate of increase in future compensation levels used in measuring the life insurance accumulated postretirement benefit obligation was 4.5% for December 31, 1994 and December 31, 1993 and 5.5% for January 1, 1993. A 12.0 percent annual rate of increase in the per capita cost of covered health care benefits was assumed for 1994; the rate is assumed to decrease gradually to 4.5% by the year 2006 and remain at that level thereafter. A one-percentage-point increase in the assumed health care cost trend rates would increase the accumulated postretirement benefit obligation as of December 31, 1994 by approximately $7.3 million, and the aggregate of the service and interest cost components of net postretirement health care cost for 1994 by approximately $1.0 million.

The following table sets forth the funded status of the postretirement benefits and amounts recognized in the Company's Consolidated Balance Sheets as of December 31, 1994 and December 31, 1993:

(DOLLARS IN THOUSANDS)	DEC 31, 1994	DEC 31, 1993	JAN 1, 1993
Accumulated postretirement benefit obligation:			
Retirees	$ (81,688)	$ (42,891)	$ (45,152)
Actives eligible to retire	(2,716)	(17,479)	(15,341)
Actives not yet eligible to retire	(7,870)	(15,622)	(13,241)
Total	(92,274)	(75,992)	(73,734)
Plan assets at fair value	17,279	--	--
Funded status	(74,995)	(75,992)	(73,734)
Unrecognized transition obligation	49,483	70,047	73,734
Unrecognized net actuarial gain	(2,930)	(2,908)	--
Accrued postretirement benefit obligation	$ (28,442)	$ (8,853)	$ --

POSTEMPLOYMENT BENEFITS

In November 1992, the FASB issued SFAS No. 112, "Employers' Accounting for Postemployment Benefits," which requires the accrual of the estimated cost of benefits provided to former or inactive employees after employment but before retirement. The Company adopted this new standard effective January 1, 1994, recording $4.7 million of postemployment benefits cost for the year.

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8. REPORT OF BUSINESS SEGMENTS

The Company's electric utility segment is an operating public utility engaged in the generation, transmission, distribution and sale of electric energy. The non-utility subsidiary segment is engaged in the gathering and transmission of natural gas, and through its subsidiaries, is engaged in the processing of natural gas and the marketing of natural gas liquids, in the buying and selling of natural gas to third parties, and in the exploration for and production of natural gas and related products.

(DOLLARS IN THOUSANDS)	1994	1993	1992
Operating Information:			
Operating Revenues			
Electric utility	$ 1,196,898	$ 1,282,816	$1,193,993
Non-utility subsidiary	203,079	219,376	189,574
Intersegment revenues (A)	(44,809)	(54,940)	(68,583)
Total	$ 1,355,168	$ 1,447,252	$1,314,984
Pre-tax Operating Income			
Electric utility	$ 248,827	$ 238,761	$ 206,350
Non-utility subsidiary	23,710	28,531	30,860
Total	$ 272,537	$ 267,292	$ 237,210
Net Income			
Electric utility	$ 113,795	$ 104,730	$ 88,293
Non-utility subsidiary	9,990	9,547	11,419
Total	$ 123,785	$ 114,277	$ 99,712
Investment Information:			
Identifiable Assets as of December 31			
Electric utility	$ 2,471,902	$ 2,443,651	$2,358,661
Non-utility subsidiary	310,727	287,773	231,422
Total	$ 2,782,629	$ 2,731,424	$2,590,083
Other Information:			
Depreciation			
Electric utility	$ 107,239	$ 104,343	$ 100,531
Non-utility subsidiary	19,138	15,200	10,169
Total	$ 126,377	$ 119,543	$ 110,700
Construction Expenditures			
Electric utility	$ 104,256	$ 105,746	$ 109,650
Non-utility subsidiary	45,634	22,396	30,601
Total	$ 149,890	$ 128,142	$ 140,251

(A) Intersegment revenues are recorded at prices comparable to those of unaffiliated customers and are affected by regulatory considerations.

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9. COMMITMENTS AND CONTINGENCIES

The Company has entered into purchase commitments in connection with its construction program and the purchase of necessary fuel supplies of coal and natural gas for its generating units. The Company's construction expenditures for 1995 are estimated at $89 million.

The Company acquires natural gas for boiler fuel under 738 individual contracts, some of which contain provisions allowing the owners to require prepayments for gas if certain minimum quantities are not taken. At December 31, 1994, 1993 and 1992, outstanding prepayments for gas, including the amounts classified as current assets, under these contracts were approximately $10,879,000, $22,165,000 and $24,543,000, respectively. The Company may be required to make additional prepayments in subsequent years. The Company expects to recover these prepayments as fuel costs if unable to take the gas prior to the expiration of the contracts.

At December 31, 1994, the Company held non-cancelable operating leases covering approximately 1,500 coal hopper railcars. Rental payments are charged to fuel expense and recovered through the Company'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)

1995	$ 5,530	1998	$ 5,214
1996	5,425	1999	5,108
1997	5,319	2000 and beyond	110,012
Total Minimum Lease Payments			$ 136,608

Rental payments under operating leases were approximately $5.6 million in 1994, $4.9 million in 1993 and $3.6 million in 1992.

OG&E is required to maintain the railcars it has under lease to transport coal from Wyoming and has entered into an agreement with Railcar Maintenance Company, a non-affiliated company, to furnish this maintenance.

The Company has entered into an agreement with an unrelated third party to develop a natural gas storage facility. Pursuant to that agreement, the Company made cash advances to the developer amounting to approximately $38.8 million, as of December 31, 1994, which is included in Prepayments and other on the accompanying Consolidated Balance Sheets. Upon completion of the storage facility, it is anticipated that the developer will obtain alternative financing for the project and repay the cash advances. OG&E will utilize the facility on a fee basis.

The Company 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 the Company to purchase power generated in a manufacturing process from a qualified cogeneration facility ("QF"). The rate for such power to be paid by the Company was approved by the Oklahoma Commission. The rate generally consists of two components: one is a rate for actual electricity purchased from the QF by the Company; the other is a capacity charge which the Company must pay the QF for having the capacity available. However, if no electrical power is made available to the Company for a period of time (generally three months), the Company's obligation to pay the capacity charge is suspended. The total cost of cogeneration payments is currently recoverable in rates from Oklahoma customers.

During 1994, 1993 and 1992, OG&E made total payments to cogenerators of approximately $210.3 million, $213.0 million and $179.4 million, of which $173.2 million, $165.5 million and $101.6 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: 1995 - $174 million, 1996 - $175 million, 1997 - $176 million, 1998 - $184 million and 1999 - $189 million.

Approximately $7.4 million of the Company's construction expenditures budgeted for 1995 are to comply with environmental laws and regulations.

The Company continues to explore options to comply with the Clean Air Act Amendments of 1990 ("CAAA"). Since all of OG&E's coal-fired generating units currently burn low-sulfur coal, OG&E will not need to take any steps to comply with the new sulfur dioxide emission limits until January 1, 2000. In compliance with Title IV of the CAAA, the Company has completed installation of continuous emission monitors ("CEMs") on each of its five coal-fired generating units and three of its 12 gas-fired generating units. Expenditures on CEMs in 1994 totaled approximately $6 million. The Environmental Protection Agency ("EPA") established a time extension for installation of CEMs on gas-fired

units which allowed the Company to defer CEM installation on the remaining nine units subject to the requirements of Title IV. Completion of this project is expected to cost approximately $1million during 1995. The CAAA Title V operating permits are expected to cost approximately $400,000 in 1995.

The CAAA will also regulate emissions of nitrogen oxides and certain air toxic compounds. Although final regulations concerning all of these issues have not been written, additional capital expenditures may be necessary in future years. The Company will continue to examine all alternatives to comply with the CAAA as part of its Integrated Resource Planning process. This planning approach will assure the Company employs the least cost option to comply with the CAAA and be in a competitive position to market its services.

The Company is a party to three separate actions brought by the EPA concerning cleanup of disposal sites for hazardous waste. The Company was not the owner or operator of those sites. Rather, the Company along with many others, shipped materials to the owners or operators of the sites who failed to dispose of the materials in an appropriate manner. The Company has calculated that its portion of total waste disposed at the sites is relatively minor. The cost of complying with the EPA sanctions at these sites is difficult to estimate. However, based on the relative percentage attributed to the Company and other considerations, management believes the ultimate outcome of these matters will not have a material adverse effect on the Company's consolidated financial position or results of operations.

In 1992, OG&E began a voluntary review of information contained in the annual report required under the Toxic Substance Control Act ("TSCA") for 1991. The initial result of the review revealed some discrepancies in operating practices and documentation. The EPA was notified of these initial discrepancies in December 1992. Because it was suspected that additional discrepancies might be discovered during the continuing review/audit, OG&E reached an agreement on January 12, 1993, with the EPA, Region VI, concerning the notification and reporting requirements of any newly discovered discrepancies.

After further investigation, OG&E reported in September 1993 numerous additional discrepancies to the EPA, Region VI. Many of the discrepancies could be deemed violations of the regulations under TSCA. Under the TSCA regulations, the EPA has the authority to assess a maximum fine of up to $25,000 per day, and to treat each day of violation as the basis for a separate fine. OG&E has taken and is taking corrective action to remedy the discrepancies.

The position of the EPA and OG&E is that they are currently in pre-settlement negotiations. Since this matter is currently being negotiated, OG&E does not know the amount of fines that the EPA may seek. The amount of the fine is dependent upon numerous interpretative issues under the TSCA regulations and potentially could be significant to the Company's results of operations. However, at the present time, the Company does not expect that the amount of the fine will have a material effect on its results of operations based primarily on having voluntarily reported the discrepancies to the EPA coupled with the Company's efforts to remedy the discrepancies and the lack of releases into the environment or harm to individuals.

In the normal course of business, other lawsuits, claims, environmental actions, and other governmental proceedings arise against the Company. 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.

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10. RATE MATTERS AND REGULATION

On February 25, 1994, the Oklahoma Commission issued an order that, among other things, lowered OG&E's rates to its Oklahoma retail customers by approximately $14 million annually (based on a test year ended June 30, 1991) and required OG&E to refund approximately $41.3 million. The $14 million annual reduction in rates was expected to lower OG&E's rates to its Oklahoma customers by approximately $17 million annually. With respect to the $41.3 million refund, $39.1 million was associated with revenues prior to January 1, 1994, while the remaining $2.2 million related to 1994.

During the first half of 1992 the Company participated in settlement negotiations and offered a proposed refund and a reduction in rates in an effort to reach settlement and conclude the proceedings. As a result, the Company recorded an $18 million provision for a potential refund in 1992. After receiving the February 25, 1994 order, the Company recorded an additional provision for rate refund of approximately $21.1 million in 1993, (consisting of a $14.9 million reduction in

revenue and $6.2 million in interest) which reduced net income by some $13 million or $0.32 per share.

Enogex transports natural gas to OG&E for use at its gas-fired generating units and performs related gas gathering activities for OG&E. The entire $41.3 million refund relates to the Oklahoma Commission's disallowance of a portion of the fees paid by OG&E to Enogex for such services in the past. Of the approximately $17 million annual rate reduction, approximately $9.9 million reflects the Oklahoma Commission's reduction of the amount to be recovered by OG&E from its Oklahoma customers for the future performance of such services by Enogex.

As discussed in Note 7 of Notes to Consolidated Financial Statements, during the third quarter of 1994, the Company incurred $63.4 million of costs related to the Voluntary Early Retirement Package ("VERP") and enhanced severance package. Pending an Oklahoma Commission order, OG&E deferred these costs; however, between August 1, and December 31, 1994, the amount deferred was reduced by approximately $14.5 million. In response to an application filed by OG&E on August 9, 1994, the Oklahoma Commission issued an order on October 26, 1994, that permitted the Company to amortize the December 31, 1994, regulatory asset of $48.9 million over 26 months and reduced OG&E's electric rates by approximately $15 million annually, effective January 1995. The Company anticipates that labor savings from the VERP and severance package will substantially offset the amortization of the regulatory asset and annual rate reduction of $15 million.

The components of Deferred Charges - Other, on the Consolidated Balance Sheets included the following, as of December 31:

(DOLLARS IN THOUSANDS)	1994	1993	1992
Regulatory asset (restructuring)	$ 48,903	$ --	$ --
Unamortized debt expense	12,871	14,146	15,462
Enogex gas sales contracts	12,690	--	--
Unamortized loss on reacquired debt	5,487	5,711	5,935
Miscellaneous	12,391	24,398	16,330
Total	$ 92,342	$ 44,255	$ 37,727

Regulatory Assets and Liabilities consisted of the following as of December 31:

(DOLLARS IN THOUSANDS)	1994	1993	1992
Regulatory Assets:			
Income Taxes Recoverable from Customers	$ 151,086	$ 161,346	$ 44,387
Workforce Reduction	48,903	--	--
Miscellaneous.	2,214	12,090	5,453
Total Regulatory Assets	202,203	173,436	49,840
Regulatory Liabilities:			
Income Taxes Refundable to Customers	(103,840)	(113,753)	(44,387)
Gain on Disposition of Allowances	(187)	(79)	--
Net Regulatory Assets	$ 98,176	$ 59,604	$ 5,453

While the Company does not expect to cease meeting the criteria for application of SFAS No. 71 in the foreseeable future, if the Company were required to discontinue the application of SFAS No. 71 for some or all of its operations, it would result in writing off the related regulatory assets; the financial effects of which could be significant.

11. DISCLOSURES ABOUT FAIR VALUE OF FINANCIAL INSTRUMENTS

The following methods and assumptions were used to estimate the fair value of each class of financial instruments:

CASH AND CASH EQUIVALENTS AND CUSTOMER DEPOSITS

The fair value of cash and cash equivalents and customer deposits approximate the carrying amount due to their short maturity.

CAPITALIZATION

The fair value of Long-term Debt and Preferred Stocks 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:

(DOLLARS IN THOUSANDS)	1994 CARRYING AMOUNT	1994 FAIR VALUE	1993 CARRYING AMOUNT	1993 FAIR VALUE	1992 CARRYING AMOUNT	1992 FAIR VALUE
ASSETS:						
CASH AND CASH EQUIVALENTS	$ 2,455	$ 2,455	$ 6,593	$ 6,593	$ 11,316	$ 11,316
LIABILITIES:						
CUSTOMER DEPOSITS	$ 20,904	$ 20,904	$ 19,353	$ 19,353	$ 17,891	$ 17,891
CAPITALIZATION:						
First Mortgage Bonds	$ 716,967	$ 710,523	$ 716,610	$ 749,684	$ 731,254	$ 740,755
Industrial Trust Bonds	32,050	32,044	32,400	32,604	32,700	32,746
Enogex Inc. Notes	6,900	6,900	90,000	100,486	90,000	95,715
Preferred Stock:						
4% Series through 5.34% Series-- 838,663 Shares outstanding	49,973	27,442	49,973	34,523	49,973	31,332
Total	$ 805,890	$ 776,909	$ 888,983	$ 917,297	$ 903,927	$ 900,548

On January 1, 1994, SFAS No. 115, "Accounting for Certain Investments in Debt and Equity Securities," became effective. This did not have a material adverse impact on the Company's consolidated financial position or results of operations.

REPORT OF INDEPENDENT PUBLIC ACCOUNTANTS

TO THE SHAREOWNERS OF
OKLAHOMA GAS AND ELECTRIC COMPANY:

We have audited the accompanying consolidated balance sheets and statements of capitalization of Oklahoma Gas and Electric Company (an Oklahoma corporation) and its subsidiaries as of December 31, 1994, 1993 and 1992, 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 generally accepted auditing standards. 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 Oklahoma Gas and Electric Company and its subsidiaries as of December 31, 1994, 1993 and 1992, and the results of their operations and their cash flows for the years then ended in conformity with generally accepted accounting principles.

/s/ ARTHUR ANDERSEN LLP

Oklahoma City, Oklahoma,
January 26, 1995

REPORT OF MANAGEMENT

TO OUR SHAREOWNERS:

The management of Oklahoma Gas and Electric Company and its subsidiaries has prepared, and is responsible for the integrity and objectivity of the financial and operating information contained in this Annual Report. The consolidated financial statements have been prepared in accordance with generally accepted accounting principles and include certain amounts that are based on the best estimates and judgments of management.

To meet its responsibility for the reliability of the consolidated financial statements and related financial data, the Company's management has established and maintains an internal control structure. This structure provides management with reasonable assurance in a cost-effective manner that, among other things, assets are properly safeguarded and transactions are executed and recorded in accordance with its authorizations so as to permit preparation of financial statements in accordance with generally accepted accounting principles. The Company's internal auditors assess the effectiveness of this internal control structure and recommend possible improvements thereto on an ongoing basis.

The Company maintains high standards in selecting, training and developing its members. This, combined with Company policies and procedures, provides reasonable assurance that operations are conducted in conformity with applicable laws and with its commitment to the highest standards of business conduct.

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	1994	$281,388	$443,173	$346,623	$283,984
	1993	301,392	500,639	341,799	303,422
	1992	304,093	443,327	306,341	261,223
Operating income	1994	$ 23,792	$105,563	$ 50,427	$ 20,684
	1993	18,899	111,576	39,457	25,221
	1992	32,043	94,319	36,072	14,570
Net income (loss)	1994	$ 4,952	$ 86,251	$ 31,082	$ 1,500
	1993	(3,619)	90,810	20,396	6,690
	1992	10,629	76,035	17,015	(3,967)
Earnings (loss) available for common	1994	$ 4,372	$ 85,672	$ 30,503	$ 921
	1993	(4,199)	90,231	19,817	6,111
	1992	10,050	75,456	16,436	(4,547)
Earnings (loss) per average common share ...	1994	$ 0.11	$ 2.12	$ 0.76	$ 0.02
	1993	(0.10)	2.24	0.49	0.15
	1992	0.25	1.87	0.41	(0.11)

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 OG&E filed copies of a definitive proxy statement with the Securities and Exchange Commission on or about March 29, 1995. 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, 1994, 1993 and 1992
- Consolidated Statements of Income for the years ended December 31, 1994, 1993 and 1992
- Consolidated Statements of Retained Earnings for the years ended December 31, 1994, 1993 and 1992
- Consolidated Statements of Capitalization at December 31, 1994, 1993 and 1992
- Consolidated Statements of Cash Flows for the years ended December 31, 1994, 1993 and 1992
- 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)

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Schedule II - Valuation and qualifying accounts	59
Report of Independent Public Accountants	60

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
3.01	Copy of Restated Certificate of Incorporation. (Filed as Exhibit 4.01 to the Company's Post-Effective Amendment No. Three to Registration Statement No. 2-94973, and incorporated by reference herein)
3.02	By-laws. (Filed as Exhibit 4.02 to Post-Effective Amendment No. Three to Registration Statement No. 2-94973 and incorporated by reference herein)
4.01	Copy of Trust Indenture, dated February 1, 1945, from OG&E to The First National Bank and Trust Company of Oklahoma City, Trustee. (Filed as Exhibit 7-A to Registration Statement No. 2-5566 and incorporated by reference herein)
4.02	Copy of Supplemental Trust Indenture, dated December 1, 1948, being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 7.03 to Registration Statement No. 2-7744 and incorporated by reference herein)
4.03	Copy of Supplemental Trust Indenture, dated June 1, 1949, being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 7.03 to Registration Statement No. 2-7964 and incorporated by reference herein)
4.04	Copy of Supplemental Trust Indenture, dated May 1, 1950, being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 7.04 to Registration Statement No. 2-8421 and incorporated by reference herein)
4.05	Copy of Supplemental Trust Indenture, dated March 1, 1952, a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 4.08 to Registration Statement No. 2-9415 and incorporated by reference herein)

4.06 Copy of Supplemental Trust Indenture, dated June 1, 1955, being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 4.07 to Registration Statement No. 2-12274 and incorporated by reference herein)

4.07 Copy of Supplemental Trust Indenture, dated January 1, 1957, being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 2.07 to Registration Statement No. 2-14115 and incorporated by reference herein)

4.08 Copy of Supplemental Trust Indenture, dated June 1, 1958, being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 4.09 to Registration Statement No. 2-19757 and incorporated by reference herein)

4.09 Copy of Supplemental Trust Indenture, dated March 1, 1963, being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 2.09 to Registration Statement No. 2-23127 and incorporated by reference herein)

4.10 Copy of Supplemental Trust Indenture, dated March 1, 1965, being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 4.10 to Registration Statement No. 2-25808 and incorporated by reference herein)

4.11 Copy of Supplemental Trust Indenture, dated January 1, 1967, being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 2.11 to Registration Statement No. 2-27854 and incorporated by reference herein)

4.12 Copy of Supplemental Trust Indenture, dated January 1, 1968, being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 2.12 to Registration Statement No. 2-31010 and incorporated by reference herein)

4.13 Copy of Supplemental Trust Indenture, dated January 1, 1969, being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 2.13 to Registration Statement No. 2-35419 and incorporated by reference herein)

4.14 Copy of Supplemental Trust Indenture, dated

January 1, 1970, being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 2.14 to Registration Statement No. 2-42393 and incorporated by reference herein)

4.15 Copy of Supplemental Trust Indenture, dated January 1, 1972, being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 2.15 to Registration Statement No. 2-49612 and incorporated by reference herein)

4.16 Copy of Supplemental Trust Indenture, dated January 1, 1974, being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 2.16 to Registration Statement No. 2-52417 and incorporated by reference herein)

4.17 Copy of Supplemental Trust Indenture, dated January 1, 1975, being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 2.17 to Registration Statement No. 2-55085 and incorporated by reference herein)

4.18 Copy of Supplemental Trust Indenture, dated January 1, 1976, being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 2.18 to Registration Statement No. 2-57730 and incorporated by reference herein)

4.19 Copy of Supplemental Trust Indenture, dated September 14, 1976, being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 2.19 to Registration Statement No. 2-59887 and incorporated by reference herein)

4.20 Copy of Supplemental Trust Indenture, dated January 1, 1977, being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 2.20 to Registration Statement No. 2-59887 and incorporated by reference herein)

4.21 Copy of Supplemental Trust Indenture, dated November 1, 1977, being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 4.21 to Registration Statement No. 2-70539 and incorporated by reference herein)

4.22 Copy of Supplemental Trust Indenture, dated December 1, 1977, being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 4.22 to Registration Statement No. 2-70539 and incorporated by reference herein)

4.23 Copy of Supplemental Trust Indenture, dated February 1, 1980, being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 4.23 to Registration Statement No. 2-70539 and incorporated by reference herein)

4.24 Copy of Supplemental Trust Indenture, dated April 15, 1982, being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 4.24 to the Company's Form 10-K Report, File No. 1-1097, for the year ended December 31, 1982, and incorporated by reference herein)

4.25 Copy of Supplemental Trust Indenture, dated August 15, 1986, being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 4.25 to the Company's Form 10-K Report, File No. 1-1097, for the year ended December 31, 1986 and incorporated by reference herein)

4.26 Copy of Supplemental Trust Indenture, dated March 1, 1987, being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 4.26 to the Company's Form 10-K Report for the year ended December 31, 1987, File No. 1-1097, and incorporated by reference herein)

4.28 Copy of Supplemental Trust Indenture, dated November 15, 1990, being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 4.28 to the Company's Form 10-K Report for the year ended December 31, 1990, File No. 1-1097, and incorporated by reference herein)

4.29 Copy of Supplemental Trust Indenture, dated December 9, 1991, being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 4.29 to the Company's Form 10-K Report for the year ended December 31, 1991, 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.

10.05 Participation Agreement dated as of January 1, 1980, among First National Bank and Trust Company of Oklahoma City, Thrall Car Manufacturing Company, OG&E and other parties, including Lease of Railroad Equipment dated January 1, 1980, between Mercantile-Safe Deposit and Trust Company and OG&E. (Filed as Exhibit 10.32 to the Company's Form 10-K Report for the year ended December 31, 1980, File No. 1-1097, and incorporated by reference herein)

10.06 Participation Agreement dated January 1, 1981, among The First National Bank and Trust Company of Oklahoma City, Thrall Car Manufacturing Company, OG&E and other parties, including Lease for Railroad Equipment dated January 1, 1981, between Wells Fargo Equipment Leasing Corporation and OG&E. (Filed as Exhibit 20.01 to the Company's Form 10-Q for June 30, 1981, File No. 1-1097, and incorporated by reference herein)

10.08 Form of Amended and Restated Stock Equivalent and Deferred Compensation Agreement for Directors, as amended.

10.09 Restricted Stock Plan of the Company. (Filed as Exhibit 10.36 to the Company's Form 10-K Report for the year ended December 31, 1986, File No. 1-1097, and incorporated by reference herein)

10.10 Agreement and Plan of Reorganization, dated May 14, 1986, between OG&E and Mustang Fuel Corporation. (Attached as Appendix A to Registration Statement No. 33-7472 and incorporated by reference herein)

10.11 Gas Service Agreement dated January 1, 1988, between OG&E and Oklahoma Natural Gas Company. (Filed as Exhibit 10.26 to the Company's Form 10-K Report for the year ended December 31, 1987, File No. 1-1097, and incorporated by reference herein)

10.12 Company's Restoration of Retirement Income Plan, as amended. (Filed as Exhibit 10.12 to the Company's Form 10-K Report for the year ended December 31, 1993, File No. 1-1097 and incorporated by reference herein)

10.13 Company's Restoration of Retirement Savings Plan. (Filed as Exhibit 10.13 to the Company's Form 10-K Report for the year ended December 31, 1993, File No. 1-1097 and incorporated by reference herein)

10.14 Gas Service Agreement dated July 23, 1987, between OG&E and Arkla Services Company. (Filed as Exhibit 10.29 to the Company's Form 10-K Report for the year ended December 31, 1987, File No. 1-1097, and incorporated by reference herein)

10.15 Company's Supplemental Executive Retirement Plan.

(Filed as Exhibit 10.1 to the Company's Form 10-K Report for the year ended December 31, 1993, File No. 1-1097 and incorporated by reference herein)

10.16 Company's Annual Incentive Compensation Plan. (Filed as Exhibit 10.16 to the Company's Form 10-K Report for the year ended December 31, 1993, File No. 1-1097, and incorporated by reference herein)

23.01 Consent of Arthur Andersen LLP.

24.01 Power of Attorney.

27.01 Financial Data Schedule.

99.01 1994 Form 11-K Annual Report for Oklahoma Gas and Electric Company Employees' Retirement Savings Plan.

99.02 Description of Common Stock.

Executive Compensation Plans and Arrangements

10.08 Form of Amended and Restated Stock Equivalent and Deferred Compensation Agreement for Directors, as amended.

10.09 Restricted Stock Plan of the Company. (Filed as Exhibit 10.36 to the Company's Form 10-K Report for the year ended December 31, 1986, File No. 1-1097, and incorporated by reference herein)

10.12 Company's Restoration of Retirement Income Plan, as amended. (Filed as Exhibit 10.12 to the Company's Form 10-K Report for the year ended December 31, 1993, File No. 1-1097 and incorporated by reference herein)

10.13 Company's Restoration of Retirement Savings Plan. (Filed as Exhibit 10.13 to the Company's Form 10-K Report for the year ended December 31, 1993, File No. 1-1097 and incorporated by reference herein)

10.15 Company's Supplemental Executive Retirement Plan. (Filed as Exhibit 10.15 to the Company's Form 10-K Report for the year ended December 31, 1993, File No. 1-1097 and incorporated by reference herein)

10.16 Company's Annual Incentive Compensation Plan. (Filed as Exhibit 10.16 to the Company's Form 10-K Report for the year ended December 31, 1993, File No. 1-1097 and incorporated by reference herein)

(B) REPORTS ON FORM 8-K

Item 5. Other Events, dated February 28, 1994.
Item 5. Other Events, dated April 29, 1994.
Item 5. Other Events, dated October 28, 1994.

OKLAHOMA GAS AND ELECTRIC COMPANY

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
		(THOUSANDS)			
1994					
Reserve for Uncollectible Accounts	$4,070	$6,767	-	$7,118	$3,719
1993					
Reserve for Uncollectible Accounts	$4,039	$6,669	-	$6,638	$4,070
1992					
Reserve for Uncollectible Accounts	$3,775	$7,549	-	$7,285	$4,039

REPORT OF INDEPENDENT PUBLIC ACCOUNTANTS

To Oklahoma Gas and Electric Company:

We have audited in accordance with generally accepted auditing standards, the consolidated financial statements of Oklahoma Gas and Electric Company included in this Form 10-K, and have issued our report thereon dated January 26, 1995. Our audits were made for the purpose of forming an opinion on those statements taken as a whole. The schedule listed on Page 51, 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 26, 1995

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 29th day of March, 1995.

OKLAHOMA GAS AND ELECTRIC COMPANY
(REGISTRANT)

/s/ J. G. Harlow Jr.
By J. G. Harlow Jr.
Chairman of the Board
and President

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/ J. G. Harlow Jr. J. G. Harlow Jr.	Principal Executive Officer and Director;	March 29, 1995
/s/ A. M. Strecker A. M. Strecker	Principal Financial Officer; and	March 29, 1995
/s/ D. L. Young D. L. Young	Principal Accounting Officer.	March 29, 1995
Herbert H. Champlin	Director;	
William E. Durrett	Director;	
Martha W. Griffin	Director;	
Hugh L. Hembree, III	Director;	
John F. Snodgrass	Director;	
Bill Swisher	Director;	
John A. Taylor	Director; and	
Ronald H. White, M.D.	Director.	

By J. G. Harlow Jr. (attorney-in-fact) March 29, 1995
/s/ J. G. Harlow Jr.

EXHIBIT INDEX

EXHIBIT NO.	DESCRIPTION
3.01	Copy of Restated Certificate of Incorporation. (Filed as Exhibit 4.01 to the Company's Post-Effective Amendment No. Three to Registration Statement No. 2-94973, and incorporated by reference herein)
3.02	By-laws. (Filed as Exhibit 4.02 to Post-Effective Amendment No. Three to Registration Statement No. 2-94973 and incorporated by reference herein)
4.01	Copy of Trust Indenture, dated February 1, 1945, from OG&E to The First National Bank and Trust Company of Oklahoma City, Trustee. (Filed as Exhibit 7-A to Registration Statement No. 2-5566 and incorporated by reference herein)
4.02	Copy of Supplemental Trust Indenture, dated December 1, 1948, being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 7.03 to Registration Statement No. 2-7744 and incorporated by reference herein)
4.03	Copy of Supplemental Trust Indenture, dated June 1, 1949, being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 7.03 to Registration Statement No. 2-7964 and incorporated by reference herein)
4.04	Copy of Supplemental Trust Indenture, dated May 1, 1950, being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 7.04 to Registration Statement No. 2-8421 and incorporated by reference herein)
4.05	Copy of Supplemental Trust Indenture, dated March 1, 1952, a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 4.08 to Registration Statement No. 2-9415 and incorporated by reference herein)
4.06	Copy of Supplemental Trust Indenture, dated June 1, 1955, being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 4.07 to Registration Statement No. 2-12274 and incorporated by reference herein)
4.07	Copy of Supplemental Trust Indenture, dated January 1, 1957, being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 2.07 to Registration Statement No. 2-14115 and incorporated by reference herein)
4.08	Copy of Supplemental Trust Indenture, dated June 1, 1958, being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 4.09 to Registration Statement No. 2-19757 and incorporated by reference herein)
4.09	Copy of Supplemental Trust Indenture, dated March 1, 1963, being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 2.09 to Registration Statement No. 2-23127 and incorporated by reference herein)

4.10 Copy of Supplemental Trust Indenture, dated March 1, 1965, being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 4.10 to Registration Statement No. 2-25808 and incorporated by reference herein)

4.11 Copy of Supplemental Trust Indenture, dated January 1, 1967, being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 2.11 to Registration Statement No. 2-27854 and incorporated by reference herein)

4.12 Copy of Supplemental Trust Indenture, dated January 1, 1968, being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 2.12 to Registration Statement No. 2-31010 and incorporated by reference herein)

4.13 Copy of Supplemental Trust Indenture, dated January 1, 1969, being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 2.13 to Registration Statement No. 2-35419 and incorporated by reference herein)

4.14 Copy of Supplemental Trust Indenture, dated January 1, 1970, being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 2.14 to Registration Statement No. 2-42393 and incorporated by reference herein)

4.15 Copy of Supplemental Trust Indenture, dated January 1, 1972, being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 2.15 to Registration Statement No. 2-49612 and incorporated by reference herein)

4.16 Copy of Supplemental Trust Indenture, dated January 1, 1974, being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 2.16 to Registration Statement No. 2-52417 and incorporated by reference herein)

4.17 Copy of Supplemental Trust Indenture, dated January 1, 1975, being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 2.17 to Registration Statement No. 2-55085 and incorporated by reference herein)

4.18 Copy of Supplemental Trust Indenture, dated January 1, 1976, being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 2.18 to Registration Statement No. 2-57730 and incorporated by reference herein)

4.19 Copy of Supplemental Trust Indenture, dated September 14, 1976, being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 2.19 to Registration Statement No. 2-59887 and incorporated by reference herein)

4.20 Copy of Supplemental Trust Indenture, dated January 1, 1977, being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 2.20 to Registration Statement No. 2-59887 and incorporated by reference herein)

4.21 Copy of Supplemental Trust Indenture, dated

November 1, 1977, being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 4.21 to Registration Statement No. 2-70539 and incorporated by reference herein)

4.22 Copy of Supplemental Trust Indenture, dated December 1, 1977, being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 4.22 to Registration Statement No. 2-70539 and incorporated by reference herein)

4.23 Copy of Supplemental Trust Indenture, dated February 1, 1980, being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 4.23 to Registration Statement No. 2-70539 and incorporated by reference herein)

4.24 Copy of Supplemental Trust Indenture, dated April 15, 1982, being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 4.24 to the Company's Form 10-K Report, File No. 1-1097, for the year ended December 31, 1982, and incorporated by reference herein)

4.25 Copy of Supplemental Trust Indenture, dated August 15, 1986, being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 4.25 to the Company's Form 10-K Report, File No. 1-1097, for the year ended December 31, 1986 and incorporated by reference herein)

4.26 Copy of Supplemental Trust Indenture, dated March 1, 1987, being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 4.26 to the Company's Form 10-K Report for the year ended December 31, 1987, File No. 1-1097, and incorporated by reference herein)

4.28 Copy of Supplemental Trust Indenture, dated November 15, 1990, being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 4.28 to the Company's Form 10-K Report for the year ended December 31, 1990, File No. 1-1097, and incorporated by reference herein)

4.29 Copy of Supplemental Trust Indenture, dated December 9, 1991, being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 4.29 to the Company's Form 10-K Report for the year ended December 31, 1991, 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.

10.05 Participation Agreement dated as of January 1, 1980, among First National Bank and Trust Company of Oklahoma City, Thrall Car Manufacturing Company, OG&E and other parties, including Lease of Railroad Equipment dated January 1, 1980, between Mercantile-Safe Deposit and Trust Company and OG&E. (Filed as Exhibit 10.32 to the Company's Form 10-K Report for the year ended December 31, 1980, File No. 1-1097, and incorporated by reference herein)

10.06 Participation Agreement dated January 1, 1981, among The First National Bank and Trust Company of Oklahoma City, Thrall Car Manufacturing Company, OG&E and other parties, including Lease for Railroad Equipment dated January 1, 1981, between Wells Fargo Equipment Leasing Corporation and OG&E. (Filed as Exhibit 20.01 to the Company's Form 10-Q for June 30, 1981, File No. 1-1097, and incorporated by reference herein)

10.08 Form of Amended and Restated Stock Equivalent and Deferred Compensation Agreement for Directors, as amended.

10.09 Restricted Stock Plan of the Company. (Filed as Exhibit 10.36 to the Company's Form 10-K Report for the year ended December 31, 1986, File No. 1-1097, and incorporated by reference herein)

10.10 Agreement and Plan of Reorganization, dated May 14, 1986, between OG&E and Mustang Fuel Corporation. (Attached as Appendix A to Registration Statement No. 33-7472 and incorporated by reference herein)

10.11 Gas Service Agreement dated January 1, 1988, between OG&E and Oklahoma Natural Gas Company. (Filed as Exhibit 10.26 to the Company's Form 10-K Report for the year ended December 31, 1987, File No. 1-1097, and incorporated by reference herein)

10.12 Company's Restoration of Retirement Income Plan, as amended. (Filed as Exhibit 10.12 to the Company's Form 10-K Report for the year ended December 31, 1993, File No. 1-1097 and incorporated by reference herein)

10.13 Company's Restoration of Retirement Savings Plan. (Filed as Exhibit 10.13 to the Company's Form 10-K Report for the year ended December 31, 1993, File No. 1-1097 and incorporated by reference herein)

10.14 Gas Service Agreement dated July 23, 1987, between OG&E and Arkla Services Company. (Filed as Exhibit 10.29 to the Company's Form 10-K Report for the year ended December 31, 1987, File No. 1-1097, and incorporated by reference herein)

10.15 Company's Supplemental Executive Retirement Plan. (Filed as Exhibit 10.1 to the Company's Form 10-K Report for the year ended December 31, 1993, File No. 1-1097 and incorporated by reference herein)

10.16 Company's Annual Incentive Compensation Plan.
(Filed as Exhibit 10.16 to the Company's Form 10-K Report for the year ended December 31, 1993, File No. 1-1097, and incorporated by reference herein)

23.01 Consent of Arthur Andersen LLP.

24.01 Power of Attorney.

27.01 Financial Data Schedule.

99.01 1994 Form 11-K Annual Report for Oklahoma Gas and Electric Company Employees' Retirement Savings Plan.

99.02 Description of Common Stock.

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Exhibit 10.04

1990 AMENDMENT

TO THE

COAL SUPPLY AGREEMENT

BETWEEN

THUNDER BASIN COAL COMPANY

AND

OKLAHOMA GAS AND ELECTRIC COMPANY

2

1990 AMENDMENT
TO THE
COAL SUPPLY AGREEMENT

This 1990 Amendment is effective June 27, 1990 between Thunder Basin Coal Company ("Seller") and Oklahoma Gas & Electric Company ("Buyer").

Seller and Buyer are parties to a Coal Supply Agreement dated March 1, 1973, as previously amended, (the "Agreement"). The purpose of this 1990 Amendment is to further amend the Agreement as follows:

1. Section 1, "Purchase and Sale", is amended in its entirety to read as follows:

"SECTION 1 - Purchase and Sale

(a) Historical Coal Quantity

During the period January 1, 1977 through June 27, 1990 (the "Historical Period"), Seller sold to Buyer and Buyer purchased from Seller 59,426,010 tons of coal (the "Historical Coal Quantity"). Regardless of the quantity of coal Seller was obligated to sell and Buyer was obligated to purchase under the Agreement during the Historical Period, Seller and Buyer agree to accept the Historical Coal Quantity in full satisfaction of the quantity obligations of both Buyer and Seller under the Agreement during the Historical Period.

(b) Annual Quantities

Each year during the fourteen year period 1990 through 2003, Seller shall sell and Buyer shall purchase as applicable (1) the annual quantity of coal listed below ("Annual Base Quantity") or (2) the Annual Base Quantity as may be increased by Buyer under Subsection 2(b), or (3) the annual quantities Seller elects to supply under Subsection 9(i)(2)(d)(2). If the Agreement is extended under Subsection 2(c), then Seller shall sell and Buyer shall purchase the annual quantity of coal determined under Subsection 2(c).

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Period	Annual Base Quantity
1990	
1991-1998	100.32 trillion Btus
1999-2003	50.16 trillion Btus

The Annual Base Quantity for 1990 shall be the quantity of coal that equals the first 2,850,000 tons of coal purchased by Buyer during 1990 plus 50.16 trillion Btus of coal.

(c) Requirements Coal

Between June 26, 1990 and January 1, 1991 and for each calendar year during the period January 1, 1991 through December 31, 1993, Seller shall sell and Buyer shall purchase from Seller all of the coal Buyer requires for use in Units 1 and 2 at Buyer's Sooner Generating Station and Units 4, 5 and 6 at Buyer's Muskogee Generating Station up to an additional annual quantity of 31.68 trillion Btus of coal ("Requirements Coal") in excess of (1) the Annual Base Quantity plus (2) any coal which Buyer is then or is required by Oklahoma State law, regulation, or judicial or administrative order to purchase, including coal supply contracts in effect as of January 1, 1990 for coal purchased pursuant to any such law, regulation or order. Buyer represents that its commitment to purchase coal under the existing coal supply contracts with Oklahoma coal producers is 645,487 tons for the period July 1, 1990 through the expiration of the term of the last of the coal supply contracts, December 31, 1991.

Any coal delivered under the October 19, 1990 Letter Agreement between Buyer and Seller shall be deemed Requirements Coal upon execution of this 1990 Amendment and the October 19, 1990 Letter Agreement shall thereafter be void and of no effect, and neither party shall have any further obligation to the other except for any then outstanding obligation to pay for any such coal delivered under the October 19, 1990 Letter Agreement. Promptly after execution of this 1990 Amendment the price of all Requirements Coal delivered prior to the execution of the 1990 Agreement shall be retroactively adjusted to the price of Requirements Coal under this Agreement.

(d) Matching Coal Quantities and Price

(1) During the period January 1, 1994 through December 31, 1998 and the period January 1, 1999 through December 31, 2003 Seller shall have the right but not the obligation to supply, and Buyer shall purchase, the Subsection 1(d)(2) and 1 (d)(3) quantities of Matching Coal, defined below.

(A) For the purposes of this Agreement, the following definitions shall apply:

(i) "Matching Coal" shall be that quantity of Suitable Coal, in excess of the Annual Base Quantity, which is required to be purchased by Buyer pursuant to the procedures set forth in this Subsection 1(d). Buyer shall purchase Matching Coal from Seller pursuant to Seller's option to supply Matching Coal. In addition, Matching Coal may be purchased from the producer of Suitable Coal, who made the bid that yielded the corresponding Matching Coal Price under Subsection 1(d)(4), if Seller elects not to supply the corresponding quantity of Matching Coal to Buyer.

(ii) "Suitable Coal" shall mean subbituminous coal from any mine(s) located in Campbell County or Converse County, Wyoming which is producing coal at the time Buyer requests bids for Matching Coal under Subsection 1(d)(4) or requests bids for Suitable Coal under Subsection 9(i)(2)(a), as the case may be, and which is not Unacceptable Coal for any of the quality characteristics shown in Exhibit L.

(iii) "Third Party Coal" shall be coal which Buyer purchases from any producer of coal other than Seller under Subsection 1(e), during the period January 1, 1994 through December 31, 1998, which is not purchased pursuant to the procedure for the purchase of Matching Coal set forth in Subsection 1(d).

(2) During each calendar year of the period January 1, 1994 through December 31, 1998 Seller shall have the right, but not the obligation, to supply and Buyer shall purchase a quantity of Matching Coal, which Buyer requires for use in the Units (defined below) in excess of the Annual Base Quantity up to a maximum annual additional quantity of 31.68 trillion Btus of coal, except as such quantity of Matching Coal may be reduced pursuant to Subsection 1(e) "Third Party Coal." The terms "Unit" or "Units" in this Agreement shall mean as applicable: Units 1 and 2 at Buyer's Sooner Station (also known as Additional Unit 1 and Additional Unit 2 or Additional Units) and Units 4, 5, and 6 at Buyer's Muskogee Station. If Seller chooses not to supply a quantity of Matching Coal at the corresponding Matching Coal Price, then Seller's right to supply up to 31.68 trillion Btus of Matching Coal in the calendar year during which delivery is

intended by Buyer to be made (as such intent is stated in Buyer's notice to Seller under Subsection 1(d)(4) below) shall be reduced for that calendar year only by the quantity of Matching Coal Seller elected not to supply in said calendar year unless Buyer fails to purchase all or part of such quantity of Matching Coal at the corresponding Matching Coal Price in which event Seller shall again have the right to supply such unpurchased quantity of Matching Coal under the procedures of this Subsection 1(d).

(3) If Buyer purchases any Third Party Coal under Subsection 1(e), then during the period January 1, 1999 through December 31, 2003, Seller shall have the right, but not the obligation, to supply and Buyer shall purchase a quantity of Matching Coal that equals the quantity, expressed in Btus, of Third Party Coal Buyer purchased. Each time during the period January 1, 1999 through December 31, 2003 Buyer requires Suitable Coal in excess of the Annual Base Quantity, the procedures of Subsection 1(d)(4) shall be followed until Buyer has provided Seller with the right to supply the quantity of Matching Coal equal to the Third Party Coal Buyer purchased under Subsection 1(e).

(4) Each time Buyer requires Matching Coal, it shall notify Seller in writing of the quantity of such Matching Coal in Btus and the calendar year during which delivery is intended by Buyer. Buyer shall also notify Seller in writing of the Matching Coal Price(s), defined below, for the corresponding quantity of Matching Coal after Buyer establishes the Matching Coal Price(s). Buyer shall begin the process of establishing the Matching Coal Price(s) by requesting bids from producers of Suitable Coal ("Matching Coal Bids"). Buyer may establish more than one Matching Coal Price from the Matching Coal Bids and each Matching Coal Price shall correspond to the quantity of coal offered in the applicable Matching Coal Bid. In the case of a range of quantities offered in a Matching Coal Bid by the producer, Buyer shall choose the quantity of Suitable Coal at the applicable price in the Matching Coal Bid it intends to purchase from the producer submitting that Matching Coal Bid as the basis for determining a corresponding Matching Coal Price. Seller

may match any one or more of the Matching Coal Prices and supply each corresponding quantity of Matching Coal. Each time Buyer requests Matching Coal Bids, Buyer shall provide a copy of the request for Matching Coal Bids to Seller. The request for Matching Coal Bids shall require each Matching Coal Bid to (1) be for a term of supply of Suitable Coal for twelve months or less, (2) provide for a fixed per ton price (except for quality adjustments) for the corresponding quantity of Suitable Coal to be supplied and a Btu content for the Suitable Coal specified by the producer, FOB loaded in Buyer's railcars at the applicable producer's mine ("Matching Coal Bid Price"), (3) provide the same quality data as listed in Subsection 9(i)(2)(a)B and agree to the same sulfur dioxide restriction listed in Subsection 9(i)(2)(a)C, (4) be returned to

Buyer no later than the due date of the Matching Coal Bids specified by Buyer, and (5) provide for a delivery period substantially the same as intended by Buyer as stated in the request for Matching Coal Bids. Buyer shall not divulge the standards for Low Quality Suitable Coal in the requests for Matching Coal Bids. All Matching Coal Bids from producers of Suitable Coal meeting the above requirements shall be considered "Acceptable Matching Coal Bids." Buyer shall determine whether the Suitable Coal in a Matching Coal Bid is Low Quality Suitable Coal or Unacceptable Coal by following the same procedure contained in Exhibit N. Seller shall submit to Buyer the same quality data listed in Subsection 9(i)(2)(a)B by the applicable due date of the Matching Coal Bids to permit the determination of the lower heating value of Black Thunder Coal for use in determining the Matching Coal Price for any Acceptable Matching Coal Bid. Seller may also submit a Matching Coal Bid to Buyer. Buyer shall not redesignate Matching Coal as Third Party Coal after Buyer requests Matching Coal Bids.

The Matching Coal Bid Price in an Acceptable Matching Coal Bid shall be adjusted by Buyer to yield the "Matching Coal Price" following the calculation procedures provided in Exhibit N. The values for RCsc and RCbt in Exhibit N shall be equal to the following values:

RCsc	=	The weighted average per ton rail rate for transporting Suitable Coal from the applicable producer's mine to the Units in effect on the applicable due date of the Matching Coal Bids, plus the per ton railcar ownership cost (based on Buyer's best professional estimate of the cost during the period of time for which the Matching Coal Price will apply) of one (1) 112 car train set if the as received heating value of the Suitable Coal is less than 8000 Btu/lb per ton .
RCbt	=	The weighted average per ton rail rate for transporting Black Thunder Coal from Seller's Mine to the Units in effect on the applicable due date of the Matching Coal Bids.

3RCsc and RCbt shall be calculated by weighting the rail rates to the Muskogee and Sooner Stations, excluding any one-time lump sum charges or credits, by a 60%/40% proportion, respectively.

Upon receipt of the Matching Coal Price(s) and the corresponding Matching Coal quantities from Buyer, Seller shall notify Buyer within seven (7) days of receipt of the Matching Coal Price(s) whether Seller chooses to supply any one or more of the quantities of Matching Coal at the corresponding Matching Coal Price(s) or request Buyer to submit a copy of any one or more of the Acceptable Matching Coal Bid(s) and

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calculations Buyer used for the determination of the Matching Coal Price(s) to the most recent Independent Party selected under Subsection 9(i)(3) to perform the scope of work in Exhibit N (the "Verification").

If Seller has requested Verification of the Matching Coal Price(s), then Buyer and Seller shall by a joint contract with the Independent Party substantially similar to Exhibit P, which includes the scope of work in Exhibit N, cause the Independent Party to (1) complete the Verification within 20 days, (2) provide Buyer and Seller with the results of the Verification including any reasons why the Independent Party was unable to verify any Matching Coal Price, if it was unable to verify, and (3) provide it's own determination of any Matching Coal Price the Independent Party was unable to verify to Seller and Buyer. Buyer will notify Seller when the supporting documents in Section 2 of Exhibit N have been submitted to the Independent Party and of the values of RCsc and RCbt provided to the Independent Party. If the Independent Party provides its own determination of any Matching Coal Price and both Seller and Buyer do not agree with such determination, then Seller and Buyer shall then meet and endeavor in good faith to agree upon a Matching Coal Price for the corresponding quantity of Matching Coal with due regard to such determination by the Independent Party. If both Seller and Buyer do not agree upon a Matching Coal Price within seven (7) days after receipt of such Independent Party's determination of the applicable Matching Coal Price, then Buyer within four (4) days after the end of such seven (7) day period shall notify Seller either that the Matching Coal Price for the applicable quantity of Matching Coal shall be the Matching Coal Price determined by the Independent Party for that Acceptable Matching Coal Bid and the corresponding quantity of Matching Coal or that Buyer has rejected that Acceptable Matching Coal Bid. If Buyer notifies Seller that the Matching Coal Price for a quantity of Matching Coal shall be the Matching Coal Price determined by the Independent Party then Seller shall notify Buyer within four (4) days after receipt of such notice whether Seller chooses to supply the corresponding quantity of Matching Coal at that Matching Coal Price. If Buyer and Seller agree upon a Matching Coal Price during the seven (7) day period above, or if the Independent Party verified Buyer's determination of the Matching Coal Price or both Seller and Buyer agree with the Independent Party's determination of the Matching Coal Price then Seller shall notify Buyer within four (4) days after Seller's and Buyer's agreement or within four (4) days after receipt by Seller of the results of the Verification, as the case may be, whether Seller chooses to supply any of the corresponding quantities of Matching Coal at the applicable Matching Coal Price(s).

Buyer and Seller acknowledge and agree that the Matching Coal Price(s), once so determined shall be fixed for the corresponding Matching Coal quantity except for adjustments under Section 6 and Section 10.

Matching Coal supplied by Seller shall be delivered under the terms of this Agreement. Buyer shall be free to purchase from others any quantity of Matching Coal Seller declines to supply without such quantity counting as Third Party Coal.

(e) Third Party Coal

Notwithstanding Subsection 1(d) "Matching Coal Quantities and Price" Buyer may purchase up to a total quantity of 31.68 trillion Btus of coal during the period January 1, 1994 through December 31, 1998, from one or more third parties ("Third Party Coal"). If Buyer purchases Third Party Coal as provided in this Subsection 1(e) Seller shall have no right to supply Matching Coal to the extent that Third Party Coal is purchased by Buyer in any calendar year. Each time Buyer places an order for the purchase of Third Party Coal, Buyer shall inform Seller in writing promptly of such purchase, the quantity (in Btus) of Third Party Coal Buyer is purchasing and the calendar year(s) Buyer intends the Third Party Coal to be delivered.

(f) Calculation of Quantity Obligation where Third Party Coal or Matching Coal is Supplied

For purposes of determining the applicable calendar year for the supply of quantities for Third Party Coal and/or Matching Coal, the calendar year in which such Third Party Coal and/or Matching Coal is intended by Buyer to be delivered (as stated in Buyer's notice to Seller under Subsection 1(d)(4) for Matching Coal or Buyer's notice to Seller under Subsection 1(e) for Third Party Coal) shall control."

2. Section 2, "Term of Agreement and Options to Extend", shall be amended in its entirety to read as follows:

"SECTION 2 - Term of Agreement and Buyer's and Seller's Options

(a) Term

This Agreement became effective March 1, 1973 and shall continue to 11:59 pm, December 31, 2003 unless otherwise extended under Subsection 2(c)."

(b) Buyer's Option

Buyer shall have an option to increase the Annual Base Quantity for all the calendar years during the period January 1, 1999 through December 31, 2003 by the same quantity each calendar year from 50.16 trillion Btus up to a total annual quantity of 100.32 trillion Btus each calendar year by notifying

Seller in writing anytime prior to January 1, 1997. If Buyer so notifies Seller then the Annual Base Quantity shall be the annual quantity designated by Buyer which shall be greater than 50.16 trillion Btus and no more than 100.32 trillion Btus each calendar year.

(c) Seller's Option

[CONFIDENTIAL TREATMENT HAS BEEN REQUESTED. ACCORDINGLY, THIS SECTION HAS BEEN OMITTED AND FILED SEPARATELY WITH THE SECURITIES AND EXCHANGE COMMISSION.]

3. Section 4, "Increase or Decrease in Base Quantity", shall be amended in its entirety to read as follows:

"SECTION 4 - Requirements Coal Notices

By October 1 of 1991 and 1992 Buyer shall notify Seller in writing of Buyer's good faith estimate of the quantity of Requirements Coal that Buyer will require during the following year at the Units . Buyer shall notify

Seller in writing within five days of the execution of the 1990 Amendment to the Coal Supply Agreement of Buyer's good faith estimate of the quantity of Requirements Coal that Buyer will require during the remainder of 1990 and for 1991. Buyer shall also notify Seller in writing by the beginning of each quarter, January 1, April 1, July 1, October 1, during the years 1991 through 1993 of Buyer's most recent, good faith estimate of the Requirements Coal Buyer will require at the Units during the remainder of that year. The actual quantity of Requirements Coal Buyer is obligated to purchase from Seller and Seller is obligated to sell is defined in Subsection 1(c) and not by Buyer's notice in this Section 4."

4. Section 5, "Delivery Schedules" shall be amended in its entirety to read as follows:

"SECTION 5 - Delivery Schedules

Deliveries of coal under this Agreement shall be made and taken each year in approximately equal monthly amounts."

5. The first three sentences of Subsection 7(a) "Source of Coal" shall be amended in their entirety to read as follows:

"The source of coal to be sold by Seller and purchased by Buyer under the Agreement shall be Seller's Black Thunder Mine ("Seller's Mine") as it presently exists or as it may be expanded to immediately adjacent lands in Campbell County, Wyoming. Seller's Mine, as presently configured, is located within the area shown on Exhibit A. Seller warrants that at all times during the term of the Agreement it will maintain and set aside such quantity of coal reserves located within the area shown on Exhibit A (or immediately adjacent thereto if Seller's mine is expanded) as is required for the full performance of Seller's obligations hereunder (including a quantity sufficient to fulfill Seller's obligation if Buyer's option under Subsection 2(b) is exercised) and that

it will not sell nor contract to sell to others coal from said reserves in such quantity as to jeopardize Seller's ability to deliver the total quantity of coal required by this Agreement."

6. The second and third paragraphs of Section 8 "Base Price for Coal" shall be deleted and the following substituted in their place:

[CONFIDENTIAL TREATMENT HAS BEEN REQUESTED. ACCORDINGLY, THIS SECTION HAS BEEN OMITTED AND FILED SEPARATELY WITH THE SECURITIES AND EXCHANGE COMMISSION.]

7. Section 9 "Base Price Adjustments" shall be deleted through and including Subsection 9(f) and replaced with the following:

"SECTION 9 - Adjusted Base Price and Adjusted Requirements Base Price

The terms "Adjusted Base Price" and "Adjusted Requirements Base Price" as used in this Agreement shall mean, at any time, the price per ton of Annual Base Quantity coal or Requirements Coal, respectively, as most recently determined in accordance with all provisions of Subsections 9(a) through 9(d) and, if applicable, 9(f) and 9(g). Each of the adjustments to the components of the Base Price and Requirements Base Price under Subsections 9(a) through 9(c) and, if applicable, 9(d) and 9(g) shall be calculated separately.

Each of the adjusted components for the applicable Base Price under Subsections 9(a) through 9(c) shall be added together with (1) any adjustment under Subsection 9(d), plus (2), if applicable, the amount of the Fixed Component under Subsection 9(f), to equal the Adjusted Base Price. Prior to any adjustments under

Section 6 and Section 10, the Adjusted Base Price during the period June 27, 1990 through December 31, 1993 shall be reduced by the amount of any applicable Price Discount under Subsection 9(g).

The Adjusted Requirements Base Price shall be the sum of each of the adjusted components for the Requirements Base Price under Subsection 9(a) through 9(c) plus any adjustment under Subsection 9(d).

Exhibits F-2 and F-3 show the 1990 Base Price and the Requirements Base Price Components and the calculation of the Royalty and Tax Components for each Base Price as of the Base Date.

(a) Adjustments to the Base Adjustable Component

[CONFIDENTIAL TREATMENT HAS BEEN REQUESTED. ACCORDINGLY, THIS SECTION HAS BEEN OMITTED AND FILED SEPARATELY WITH THE SECURITIES AND EXCHANGE COMMISSION.]

(b) Adjustments to the (Federal and/or State) Royalty Component

[CONFIDENTIAL TREATMENT HAS BEEN REQUESTED. ACCORDINGLY, THIS SECTION HAS BEEN OMITTED AND FILED SEPARATELY WITH THE SECURITIES AND EXCHANGE COMMISSION.]

(c) Adjustments to the Tax Component (Excluding Federal Income Taxes)

[CONFIDENTIAL TREATMENT HAS BEEN REQUESTED. ACCORDINGLY, THIS SECTION HAS BEEN OMITTED AND FILED SEPARATELY WITH THE SECURITIES AND EXCHANGE COMMISSION.]

8. Subsection 9(d) "Adjustments to Compensate for Increases or Decreases Caused by Federal, State or Local Regulations"

[CONFIDENTIAL TREATMENT HAS BEEN REQUESTED. ACCORDINGLY, THIS SECTION HAS BEEN OMITTED AND FILED SEPARATELY WITH THE SECURITIES AND EXCHANGE COMMISSION.]

9. Subsection 9(e) "Buyer's Right of Rejection"

[CONFIDENTIAL TREATMENT HAS BEEN REQUESTED. ACCORDINGLY, THIS SECTION HAS BEEN OMITTED AND FILED SEPARATELY WITH THE SECURITIES AND EXCHANGE COMMISSION.]

10. A new Subsection 9(f) "Fixed Component" shall be added to Section 9.

[CONFIDENTIAL TREATMENT HAS BEEN REQUESTED. ACCORDINGLY, THIS SECTION HAS BEEN OMITTED AND FILED SEPARATELY WITH THE SECURITIES AND EXCHANGE COMMISSION.]

11. A new Subsection 9(g) "Price Discounts" shall be added to Section 9.

[CONFIDENTIAL TREATMENT HAS BEEN REQUESTED. ACCORDINGLY, THIS SECTION HAS BEEN OMITTED AND FILED SEPARATELY WITH THE SECURITIES AND EXCHANGE COMMISSION.]

12. A new Subsection 9(h) "Index or Index Publication Changes" shall be added to Section 9.

[CONFIDENTIAL TREATMENT HAS BEEN REQUESTED. ACCORDINGLY, THIS SECTION HAS BEEN OMITTED AND FILED SEPARATELY WITH THE SECURITIES AND EXCHANGE COMMISSION.]

13. A new Subsection 9(i) "Base Price Redetermination" shall be added to Section 9.

"(i) Base Price Redetermination

The Base Price of coal shall be redetermined ("Redetermined Base Price")as provided in this Subsection 9(i) effective as of January 1, 1994 and January 1, 1999 (each an "Effective Date") and, if the Agreement is extended by Seller under Subsection 2(c), also January 1, 2004 (also an "Effective Date"). In addition, the Base Price of coal may be redetermined ("Additional Base Price Redetermination") at Seller's or Buyer's option, as the case may be, under the provisions of Subsection 9(i)(2)(e), effective July 1, 1996 and July 1, 2001 respectively (each an "Effective Date") and, if the Agreement is extended by Seller under Subsection 2(c), also July 1, 2006 (also an "Effective Date"). If, despite the good faith endeavors of Buyer and Seller, the Redetermined Base Price is not available on the Effective Date, the Base Price as adjusted under this Agreement, will continue until the Redetermined Price is available and at such time a retroactive price adjustment back to the Effective Date will be made.

(1) Initial Negotiations to Establish Redetermined Base Price

During the first two weeks of that month which is nine months prior to each Effective Date, the parties shall cause their representatives to meet during normal business hours at a mutually agreeable location. The parties shall commence negotiations in good faith to attempt to agree upon a Redetermined Base Price to be effective on the Effective Date.

(2) Bids to Establish Redetermined Base Price

(a) Request for Bids for Suitable Coal

If Buyer and Seller fail to agree upon a Redetermined Base Price during the negotiations under Subsection 9(i)(1) by a date which is 180 days prior to the Effective Date, then not later than 173 days prior to the Effective Date, Buyer shall prepare and forward a Request for Bids for coal supply to those producers, including Seller, of Suitable Coal, as the term "Suitable Coal" is defined in Subsection 1(d)(1)(A)(ii). Buyer shall not divulge the standards for Low Quality Suitable Coal applicable to the Requests for Bids. The Request for Bids shall require each respondent to supply (1) Suitable Coal on the following offer basis, (2) supply the following quality data, and (3) agree to the following sulfur dioxide restriction (collectively "Bid Requirements"):

A. Offer Basis

1. Each Bid must be for a minimum quantity of 17.6 trillion Btus.

2. Each Bid must provide for a term of supply of twelve months commencing on the Effective Date.

3. Each Bid must provide for a fixed price per ton (except for quality adjustments) at a specified Btu/lb basis FOB loaded in Buyer's railcars at the applicable producer's mine (the "Bid Price").

B. Quality Data

All Quality Data shall be supplied on an "as received" basis unless otherwise stated.

1. Each Bid must include the average percent moisture, ("Bid Moisture Content"), average percent ash ("Bid Ash Content"), average percent sulfur ("Bid Sulfur Content") and average heat content expressed in Btus per pound ("Bid Btu Content") for all coal shipped from the applicable producer's mine during the last twelve months prior to the date of the Request for Bids;

2. Each Bid must include one ultimate analysis performed by an independent commercial laboratory for one unit train of coal shipped from the applicable producer's mine during the twelve month period prior to the date of the Bid Due Date [defined in Subsection 9(i)(2)(b)]. Each bid must include an indication from the independent commercial laboratory whether or not the hydrogen content in the ultimate analyses includes the hydrogen content in the moisture. If the hydrogen content in the ultimate analysis includes the hydrogen content in the moisture, then the value for the hydrogen content in the ultimate analysis shall be adjusted to exclude the hydrogen content in the moisture as shown in Exhibit J.

3. Each Bid must include the producer's representation of the average quality of the coal to be supplied from the producer's mine during the Subsection 9(i)(2)(a)A.2 term of supply for (a) volatile matter (weight percent) (b) fixed carbon (weight percent) (c) hardgrove grindability Index (d) percent alkalies as Na2O- dry coal basis (e) fusion temperatures of ash -oF - (degrees Farenheit) reducing.

C. Sulfur Dioxide Restriction

The producer shall not take exception or otherwise disclaim that the following statements, listed in the Request for Bids by Buyer, will apply to coal to be supplied by the producer to Buyer: "In the event the producer delivers to Buyer a trainload of coal exceeding 1.2 pounds sulfur dioxide per million Btus burned, Buyer shall have the option to reject such coal or pay for all such coal at a price mutually agreed

to by the producer and Buyer. If Buyer rejects the coal, the producer shall dispose of the coal at its sole cost and expense."

(b) Bid Response

Each Bid shall be due to Buyer not later than 128 days prior to the Effective Date (the "Bid Due Date") and no Bid received after the Bid Due Date shall be considered. Seller shall have the right but not the obligation to provide a Bid to Buyer. If Seller elects not to provide a Bid to Buyer, Seller shall nonetheless submit the quality data specified in Subsection 9(i)(2)(a)B.1., 2. and 3 by the Bid Due Date to permit the determination of the lower heating value of Black Thunder Coal under Subsection 9(i)(2)(d)(1) and the procedures of Exhibit J.

The Applicable Quality Information contained in the immediately succeeding paragraph, derived from the sources listed therein, must be used by Buyer to determine whether any Suitable Coal in a Bid is Low Quality Suitable Coal or Unacceptable Coal. Buyer shall determine whether any Suitable Coal in a Bid is Low Quality Suitable Coal or Unacceptable Coal as follows: (1) if any Applicable Quality Information for any Suitable Coal in a Bid falls within the quality characteristic ranges shown in Exhibit K, then that Suitable Coal must be classified as Low Quality Suitable Coal, and the "Low Quality Coal Factor" for the formula shown in Subsection 9(i)(2)(d)(1) shall equal 1.11, (2) if any Applicable Quality Information for any coal in a Bid, exceeds any one or more of the quality characteristic levels in Exhibit L then the coal in that Bid must be classified as Unacceptable Coal and the Bid shall be disqualified from further consideration.

Applicable Quality Information

1. The Bid Moisture Content supplied by the producer under 9(i)(2)(a)B.1. above.

2. The average quality data supplied by the producer under 9(i)(2)(a)B.3.

3. The weighted average as received heat content (Btus/lb.), the weighted average as received ash content (weight percent) and the weighted average as received sulfur content (weight percent) for all coal shipments reported for the respective producer's mine during the twelve (12) month period ending six (6) months prior to the month of the Bid Due Date as based on data contained in Federal Energy Regulatory Commission data, presently shown in FERC Form 423, (FERC Btu Content, FERC Ash Content, and FERC Sulfur Content, respectively). The FERC data shall be weighted on a tonnage basis. A compilation of such FERC data by a third party may be used by Buyer at Buyer's expense. If Buyer elects to use a third party to

compile such FERC data, Buyer shall inform Seller of the third party compiling the FERC data at the time Buyer selects the third party.

(c) Acceptable Bids.

An "Acceptable Bid" shall be a Bid received by Buyer from a producer of Suitable Coal that (1) meets all of the Bid Requirements, (2) is received by Buyer by the Bid Due Date and (3) covers the supply of Suitable Coal which is not Unacceptable Coal.

(d) Adjusted Bid Price, Half Volume Adjusted Bid Price and Full Volume Adjusted Bid Price

(1)

[CONFIDENTIAL TREATMENT HAS BEEN REQUESTED. ACCORDINGLY,

THIS SECTION HAS BEEN OMITTED AND FILED SEPARATELY WITH THE SECURITIES AND EXCHANGE COMMISSION.]

(2) Within 98 days prior to the Effective Date Buyer shall determine and inform Seller of the Full Volume Adjusted Bid Price and the Half Volume Adjusted Bid Price. The Full Volume Adjusted Bid Price shall be the Adjusted Bid Price for the Annual Base Quantity and the Half Volume Adjusted Bid Price shall be the Adjusted Bid Price for one-half of the Annual Base Quantity. In the case of Bids received by Buyer from multiple producers, the Full Volume Adjusted Bid Price and the Half Volume Adjusted Bid Price shall be determined by weighting the Full Volume Adjusted Bid Price and the Half Volume Adjusted Bid Price, as the case may be, by the proportion of the Btus of coal which would be supplied by each producer up to the quantity contained in each producer's Bid. Any of the Acceptable Bids may be used by Buyer in determining the Full Volume Adjusted Bid Price and the Half Volume Adjusted Bid Price. If no Acceptable Bids are received or if Buyer does not receive Acceptable Bids with sufficient quantities of Suitable Coal to equal either the Annual Base Quantity or one-half of the Annual Base Quantity for the year beginning with the Effective Date, then all or, as applicable, the remaining portion of the Full Volume Adjusted Bid Price and/or the Half Volume Adjusted Bid Price, as the case may be, shall be weighted with the remaining proportion of Btus necessary to make up the respective Full Volume Adjusted Bid Price and/or Half Volume Adjusted Bid Price at the Adjusted Base Price of coal in effect under the Agreement as of the Bid Due Date.

If Seller fails to request an Independent Party Review under Subsection 9(i)(3) "Independent Party Selection and Review" of the Full Volume Adjusted Bid Price and the Half Volume Adjusted Bid Price provided to Seller by Buyer, then by 77 days prior to the Effective Date, Seller shall inform Buyer whether Seller chooses to supply either the Annual Base Quantity at the Full Volume Adjusted Bid Price or one half of the Annual Base Quantity at the Half Volume Adjusted Bid Price ("Seller's Price Decision"). If Seller elects an Independent Party Review under Subsection 9(i)(3) "Independent Party Selection and Review", then Seller shall inform Buyer of Seller's Price Decision within seven (7) days after Seller receives the report issued by the Independent Party under Subsection 9(i)(3). The Full Volume Adjusted Bid Price or Half Volume Adjusted Bid Price, as applicable, for the quantity selected by Seller shall become the Redetermined Base Price.

If Seller's Price Decision is based on a Provisional Adjusted Bid Price(s), Buyer shall promptly inform Seller of the recalculated Full Volume Adjusted Bid Price and the Half Volume Adjusted Bid Price when and if the New Quarter Rate becomes available. However, if Seller's Price Decision was to supply one-half of the Annual Base Quantity at the Half Volume Adjusted Bid Price based on the Provisional Adjusted Bid Price(s), then Buyer shall only inform Seller of the recalculated Half Volume Adjusted Bid Price, which shall become the Redetermined Base Price, and Seller shall not have the right to choose to supply the Annual Base Quantity Coal at the Full Volume Adjusted Bid Price. If Seller's Price Decision was to supply the Annual Base Quantity at the Full Volume Adjusted Bid Price based on Provisional Adjusted Bid Price(s), then within seven (7) days after receiving Buyer's notification of the Full Volume Adjusted Bid Price and the Half Volume Adjusted Bid Price based on the New Quarter Rate or within seven (7) days after receiving the revised report reflecting the use of the New Quarter Rate from the Independent Party under the procedures of Subsection 9(i)(3), if Seller previously elected an Independent Party Review, Seller will inform Buyer of Seller's Price Decision.

If Seller previously informed Buyer that Seller would supply the Annual Base Quantity at the Full Volume Adjusted Bid Price based on Provisional Adjusted Bid Price(s) and Seller subsequently informs Buyer that Seller will supply one-half of the Annual Base Quantity at the Half Volume Adjusted Bid Price, then Buyer may notify Seller in writing, and on receipt Seller shall be obligated to supply coal at the monthly prorated Annual Base Quantity level at the Full Volume Adjusted Bid Price as previously calculated on the Provisional Adjusted Bid Price(s) for up to three months commencing on the Effective Date in order to permit Buyer to

secure an alternate supplier for the volume of coal Seller declined to supply. Buyer shall inform Seller in writing of such request within seven (7) days after Seller's Price Decision.

(e) Additional Base Price Redeterminations

If during any Redetermination of the Base Price, Seller elects to supply the Annual Base Quantity at the Full Volume Adjusted Bid Price, then Buyer may request, at Buyer's option, an Additional Base Price Redetermination by notifying Seller at least twelve (12) months prior to the next applicable Effective Date for an Additional Base Price Redetermination. However, the Base Price shall not be redetermined if the Full Volume Adjusted Bid Price determined under such Additional Base Price Redetermination is not more than 10% higher or lower than the Adjusted Base Price in effect as of the Bid Due Date.

If during any Redetermination of the Base Price, Seller elects to supply one-half of the Annual Base Quantity at the Half Volume Base Price, then Seller may request, at Seller's option, an Additional Base Price Redetermination by notifying Buyer at least twelve (12) months prior to the next applicable Effective Date for an Additional Base Price Redetermination.

After notification from either Buyer or Seller of a request for an Additional Base Price Redetermination the procedures of Subsection 9(i) and Exhibit J shall be followed to redetermine the Base Price, except as modified by this Subsection 9(i)(2)(e).

(3) Independent Party Selection and Review

Eleven (11) months prior to each applicable Effective Date, Buyer shall provide Seller with a list of three of the ten (10) largest U.S. accounting firms shown on the most recent revision of Exhibit M. The ten largest U.S. accounting firms shall be determined based on the total billings for each firm for the most recent calendar year in which billing data is available. Exhibit M lists the ten largest U.S. Accounting firms based on 1989 billings. Exhibit M shall be revised by Seller and provided to Buyer by May 15 of each year beginning May 15, 1991. Within seven days after receipt of Buyer's list, Seller shall notify Buyer of the accounting firm Seller has selected from Buyer's list to be the Independent Party to conduct any Independent Party Review under this Subsection 9(i)(3). Buyer and Seller shall then endeavor to contract with the Independent Party by nine (9) months prior to the Effective Date using a contract substantially similar to

Exhibit P to conduct an Independent Party Review (defined below) which shall be performed in accordance with a scope of work mutually agreed to by Buyer and Seller. However, any Independent Party Review shall not commence until receipt of the Notification (defined below) by the Independent Party from Seller. If Seller and Buyer are unable to agree upon the scope of work by ten (10) months prior to the Effective Date, then the scope of work outlined in Exhibit O shall apply. If, for any reason, the Independent Party is unwilling or unable to contract with Buyer and Seller to perform an Independent Party Review, then, Seller may choose another accounting firm from Buyer's list. If the next accounting firm from Buyer's list is unwilling to perform, then Buyer shall provide Seller with a list of another three accounting firms from Exhibit M and the process shall be repeated until a contract is signed with an Independent Party.

On or before 91 days prior to the Effective Date Seller may notify Buyer in writing that Seller is electing an Independent Party Review, as defined below. If Seller notifies Buyer of such an election, Seller on behalf of both Seller and Buyer shall at the time of such election also notify the Independent Party to commence to perform the Independent Party Review pursuant to the contract signed between the Independent Party, Buyer and Seller (the "Notification"). If Buyer has elected to use a third party to compile the FERC data under Subsection 9(i)(2)(b), the Notification shall indicate whether the Independent Party shall use a third party selected by Seller to compile the FERC data. The Independent Party's cost of using such a third party shall be borne by Seller. The Notification shall also indicate to the Independent Party whether the Independent Party Review is being performed on Provisional Adjusted Bid Prices, the value of the Adjusted Base Price as of the Bid Due Date and the Annual Base Quantity for the year the Redetermined Base Price is effective. Seller shall concurrently provide Buyer with a copy of the Notification.

The Independent Party Review shall verify (1) that the Bids that are the basis of the Full Volume and Half Volume Adjusted Bid Prices are Acceptable Bids and (2) that the Full Volume Adjusted Bid Price and the Half Volume Adjusted Bid Price have been correctly determined in accordance with the formula in Subsection 9(i)(2)(d)(1) and the procedures of Exhibit J ("Independent Party Review"). Within seven (7) working days after receipt of Seller's notice that Seller is electing an Independent Party Review, Buyer shall submit copies of the Bids, Buyer's calculations of the Full Volume and Half Volume Adjusted Bid Prices and all supporting data, including all quality data used in such calculations, to the Independent Party to enable the Independent Party to conduct the Independent Party Review. The supporting data provided to the Independent Party by Buyer shall include but not be limited to the number of Acceptable Bids used by Buyer in the

calculation of the Full Volume and Half Volume Adjusted Bid Prices, the quantities in trillion Btus corresponding to each Acceptable Bid, the values of RCsc and RCbt, whether Buyer used a third party in compiling the FERC data, and whether the Adjusted Base Price under the Agreement, along with the corresponding quantity in trillion Btus, was used in the calculation of such prices. Buyer will notify Seller when the supporting data has been submitted to the Independent Party and of the values of RCsc and RCbt provided to the Independent Party. Upon request by the Independent Party, Buyer shall allow the Independent Party to review the original Bids at Buyer's offices.

If the Independent Party in its sole judgment is unable to verify that either the Bids are Acceptable Bids or that Buyer's determination of the Full Volume Adjusted Bid Price and the Half Volume Adjusted Bid Price are correct, then the contract with the Independent Party shall provide that (1) the Independent Party notify Buyer and Seller in writing that it was unable to verify and (2) the Independent Party shall obtain such additional information which in its sole judgement is necessary for it to correctly establish the Full Volume Adjusted Bid Price and the Half Volume Adjusted Bid Price in accordance with Subsection 9(i)(2) and Exhibit J. After so notifying both Buyer and

Seller, the Independent Party may consult with only Buyer to assist it in obtaining such additional information needed in respect of any Bid but the Independent Party may consult with Seller, Buyer or any third party (except a third party who provided a Bid or any other coal producer or the independent lab for any coal producer) for any other additional information. The contract with the Independent Party shall provide that the Independent Party shall not consult with Seller or Buyer concerning the meaning or intent of this Agreement.

Buyer and Seller's contract with the Independent Party shall provide that the Independent Party issue a report to Seller and Buyer covering the results of the Independent Party's work by 60 days prior to the Effective Date. The report shall include only whether the Independent Party was able to make the verification in the Independent Review and, if not, the Independent Party's own determination of the Full Volume and/or Half Volume Adjusted Bid Prices in accordance with the formula in Subsection 9(i)(2)(d)(1) and the procedures of Exhibit J. If the Independent Party provides its own determination of the Full Volume and Half Volume Adjusted Bid Price, such determination shall be final (subject to revision if the Independent Party Review was conducted on Provisional Adjusted Bid Prices) and not subject to challenge by either Buyer or Seller. If Seller previously elected an Independent Party Review based on Provisional Adjusted Bid Prices, the contract with the Independent Party shall provide that the Independent Party shall issue a revised report

reflecting the use of the New Quarter Rate within seven days of receipt of the New Quarter Rate from Buyer. The expense of the Independent Party Review shall be shared equally by Seller and Buyer.

(4) Redetermined Base Price Components, Base Date, Base Indexes

When any Redetermined Base Price is established, then (1) new values shall be established for the components of the Redetermined Base Price as described below (2) the Base Date shall be changed to the applicable Effective Date for purposes of applying the Base Price adjustment procedures set forth in Subsections 9(a) through 9(d) to the Redetermined Base Price and (3) the Base Index values for A, B and C shown in Table 1 of Subsection 9(a) shall be changed to the appropriate values as specified in Table 1 of Subsection 9(a) to correspond to the new Base Date.

The values of the Redetermined Base Price components shall be determined as follows:

(a) The values of the Royalty and Tax Components covered by Subsections 9(b) and 9(c) shall be calculated upon the Redetermined Base Price, using Seller's good faith estimates of the royalty and tax amounts applicable during the year in which the Redetermined Base Price is effective. When all final values of the Royalty and Tax Components are known, (subject to audit by Buyer under Section 14 and/or governmental authorities) for the year in which the Redetermined Base Price becomes effective, the estimated values shall be replaced with the final values effective as of the Effective Date of the Redetermined Base Price. The value of the Base Adjustable Component shall then be recalculated in (c) below, the value of which shall also be effective as of the Effective Date of the Redetermined Base Price. The Current Adjustable Components calculated during the periods in which estimated values were used shall then be recalculated using the recalculated Base Adjustable Component, as provided in Subsection 9(a). Any amounts due Seller or Buyer after all final values for the Royalty and Tax Components are known, (subject to audit by Buyer under Section 14 and/or governmental authorities) and the Base Adjustable Component is recalculated and adjusted under Subsection 9(a) shall be paid by one party to the other within 15 days of receipt of Seller's invoice or credit showing the revised calculation.

(b) The sum of the values of the Royalty and Tax components determined in (a) above, shall be subtracted from the Redetermined Base Price.

(c) The remainder of the Redetermined Base Price shall become the Base Adjustable Component.

(5) Limitation on Other Changes

Neither Buyer or Seller shall demand or request that any other terms or conditions under this Agreement be altered as part of any redetermination of the Base Price."

14. Section 10 "Adjustments for Btu Value" shall be amended in its entirety to read as follows:

"SECTION 10 - Adjustments for Btu Value

The Base Price in effect from June 27, 1990 through December 31, 1993 and the Requirements Base Price per ton of coal are based upon coal having an assumed heating value of 8,800 Btu's per pound, on an "as received" basis at the Point of Delivery. Each time the Base Price is redetermined under Subsection 9(i), and each time a Matching Coal Price is determined under Subsection 1(d)(4) the Redetermined Base Price or the Matching Coal Price, as the case may be, per ton of coal will be based upon coal having an assumed heating value equal to the FERC Btu Content for Black Thunder Coal used to perform the calculation for the Full Volume Adjusted Bid Price and/or Half Volume Bid Price under Subsection 9(i)(2)(d) and Exhibit J or the Matching Coal Bid Price under the calculation procedures of Exhibit N, as the case may be ("Redetermined Heating Value").

The Adjusted Base Price, the Adjusted Requirements Base Price and the Matching Coal Price, as the case may be, shall each be further adjusted each month in order to compensate for any variations in the assumed heating value of the coal delivered hereunder during that month pursuant to the formula listed below. The following formula shall be applied separately to coal delivered to the Muskogee Units and the Sooner Units.

$$CV = AP + \left[\frac{C - B}{B} \times (AP + TC) \right]$$

Where:

CV = The price adjustment for Btu value of Annual Base Quantity Coal, Requirements Coal, or Matching Coal, as the case may be, delivered to Buyer.

AP = Adjusted Base Price or the Adjusted Requirements Base Price, as the case may be, in dollars per ton computed as provided in Section 9 or the Matching Coal Price, as the case may be.

C = Monthly weighted average Btu's per pound of Annual Base Quantity Coal, or Requirements Coal, or Matching Coal, as the case may be, on an "as received" basis for coal delivered to the Muskogee Units or the

Sooner Units, as the case may be, as determined under Section 12.

B = 8,800 Btus per pound during the period June 27, 1990 through 1993 beginning with ton number 2,850,001 on train 124BTFGC. After 1993, B shall equal the Redetermined Heating Value for Annual Base Quantity Coal or Matching Coal, as the case may be.

TC = The then current transportation rail rate (exclusive of any additional transportation- related cost) in dollars per ton from Seller's Mine to the Muskogee Units or the Sooner Units, as the case may be.

15. Subsection 13(a) shall be deleted and replaced by the following:

"On or before the fifth day after the fifteenth and the end of each calendar month, Seller shall invoice Buyer for coal delivered by Seller to Buyer during the preceding semi-monthly period. Buyer shall pay Seller within 15 days after receipt of such invoice the amount of such invoice, subject however to adjustment as provided in Subsection 13(b) below. Such invoice shall show the actual amounts of coal delivered to Buyer, as determined by Section 11 hereof, times the current Adjusted Base Price or the Adjusted Requirements Base Price or the Matching Coal Price, as the case may be, then in effect for Annual Base Quantity Coal or Requirements Coal, or Matching Coal, respectively. Both parties agree that any adjustments to prior invoices of coal affected by this 1990 Amendment shall be invoiced or credited promptly upon execution of this 1990 Amendment and payment shall be due to Seller or credit due to Buyer within 15 days of receipt of invoice.

During each calendar year of the period January 1, 1991 through December 31, 1993 Seller shall: 1) apply the Adjusted Base Price, to the first 8.36 trillion Btu's of coal delivered each month; and 2) apply the

Adjusted Requirements Base Price to all quantities of coal delivered each month in excess of 8.36 trillion Btu's, unless Buyer has given notice to Seller under Section 4 that Buyer estimates it will not purchase any Requirements Coal. However, if Buyer fails for any reason, to take at least 8.36 trillion Btu's of Annual Base Coal Quantity in any month, then the shortfall from that month shall be added to the following month's quantity to be purchased and sold at the Adjusted Base Price then in effect. For 1990 only, Seller shall apply the Adjusted Requirements Base Price to all quantities of coal delivered to Buyer after the Annual Base Quantity for 1990 has been delivered to Buyer.

Notwithstanding the provisions of the second paragraph of this Subsection 13(a), if, by July 1 of any calendar year during the period January 1, 1991 through December 31, 1993 Buyer has failed for any reason to take delivery of 50.16 trillion Btus of Annual Base Quantity Coal and Requirements Coal has been delivered during such six-month period, then all or part of such Requirements Coal shall be redesignated as Annual Base Quantity Coal until a maximum quantity of 50.16 trillion Btus has been redesignated as Annual Base Quantity Coal for such six- month period. Seller shall retroactively revise the pricing of such redesignated coal to reflect the application to such redesignated coal of the Adjusted Base Price which is in effect at the time of such redesignation. Any coal redesignated shall begin with the first Requirements Coal delivered during the six-month period. Buyer will pay Seller the increased amount due for all such redesignated coal within fifteen (15) days of receipt of Seller's invoice.

After the end of each calendar year during the period January 1, 1990 through December 31, 1993 if, for any reason, other than Seller's failure to deliver due to Seller's force majeure or Seller's default, Buyer has not taken delivery of the Annual Base Quantity during the previous calendar year, then Seller shall retroactively change the price of all Annual Base Quantity coal purchased in that year (which shall include any Requirements Coal redesignated under the immediately preceding paragraph) from the 1990, 1991, 1992, or 1993 Base Price, as the case may be, as adjusted under Sections 9 and 10, to the Alternative Base Price in effect for the year in which the Annual Base Quantity was not taken, as adjusted under Sections 9 and 10. However, for 1990, the Alternative Base Price will only apply to all coal purchased by Buyer beginning with the first ton of coal delivered after 2,850,000 tons of coal are delivered during 1990. Buyer will pay Seller the increased amount due for all such coal within fifteen (15) days of receipt of Seller's invoice. However, if Buyer has failed to take delivery of the Annual Base Quantity by one unit trainload or less, then the Base

Price shall not be retroactively changed for that year and the quantity not taken for that year shall be added to the Annual Base Quantity for the following year.

After the end of each calendar year during the period January 1, 1990 through December 31, 1993, if for any reason, the quantity of Requirements Coal taken by Buyer is different than the quantity of Requirements Coal estimated to be purchased by Buyer under Section 4 then Seller shall retroactively revise the Adjusted Base Price of Annual Base Quantity Coal to either (1) exclude the applicable Price Discounts to the extent Buyer has not taken the corresponding quantity of Requirements Coal or (2) Seller shall apply any additional applicable Price Discounts if Buyer has taken delivery of more than the estimated quantity of Requirements Coal. Any invoices for increased amounts due from Buyer or for credits due Buyer shall be issued by Seller to Buyer by January 15 after the end of each calendar year. Buyer will pay Seller any increased amount due within fifteen (15) days of receipt of Seller's invoice."

16. The fourth sentence of Subsection 15(b) "Force Majeure" beginning with "Any deficiencies..." shall be amended in its entirety to read as follows:

"Any deficiencies in deliveries of coal under this Agreement which are caused by Force Majeure shall be made up by Seller as soon as practical after determination of the effects of such Force Majeure, except to the extent, if any, (1) that Buyer was required to and did purchase other coal in order to maintain its Units in operation during such period, or cannot reasonably use any part of such deficiencies in the ordinary course of business after such determination; provided, however, that Seller shall not be required to add to or increase the capacity of its mining facilities to make up such deficiencies, or (2) that, if as a result of an event of Force Majeure, a Unit is unable to generate any electricity (Downed Unit) for a continuous period of greater than 30 days, then any deficiency in deliveries of coal so caused which remain at the end of the calendar year in which the Force Majeure event occurred shall not be made up except by mutual consent."

17. Exhibit A "Gillette Area", Exhibit B "ARCO Coal Reserve Area" and Exhibit F "Appendix A-1971 Bituminous Coal Wage Agreement" shall be deleted; the following Exhibits are incorporated: (1) Exhibit A "Black Thunder Mine Reserve Area", (2) Exhibit B "Black Thunder Royalty Provisions", (3) Exhibit F-1 "Base Prices for the Period June 27, 1990 through December 31, 1993", (4) Exhibit F-2, "1990 Base Price

Components" (5) Exhibit F-3 "Requirements Base Price Components". (6) Exhibit H "An Illustration of the Application of the Price Discounts" (7) Exhibit I "An

Illustration of a Determination of a Current Adjustable Component" (8) Exhibit J "The Determination of the Full Volume Adjusted Bid Price and the Half Volume Adjusted Bid Price" (9) Exhibit K "Low Quality Suitable Coal" (10) Exhibit L "Unacceptable Coal" (11) Exhibit M "Ten Largest U.S. Accounting Firms for 1989" (12) Exhibit N "Independent Party Scope of Work Matching Coal Price" (13) Exhibit O "Independent Party Scope of Work Full Volume and Half Volume Adjusted Bid Prices" and (14) Exhibit P "Services Agreement".

18. This 1990 Amendment and the Agreement as previously amended contain the entire Agreement between the parties with respect to the subject matter herein and supersedes all previous writings, understandings, representations or agreements with respect thereto.

19. The provisions of Subsections 9(b) and 9(c) shall survive termination or expiration of this Agreement for a period of two years.

20. Calculations performed under this Agreement shall be performed to the same decimal place as shown in the examples or illustrations shown in the Agreement. If no example or illustration is shown or unless otherwise specified, calculations shall be rounded to the fourth decimal place (0.0000). Upward rounding shall occur when the digit in the next decimal place is 5 or above. Downward rounding shall occur when the digit in the next decimal place is 4 or below.

21. Nondisclosure

Buyer and Seller agree that the following ("Confidential Information") shall be kept confidential and not disclosed to third parties:

1. The following provisions of this 1990 Amendment: Sections 2(c), 8, 9(a), through 9(h), the Exhibits F-1, F-2, F-3, H, I, J, K, and Exhibit N except Appendix 2 and Exhibit O except Appendix 2;

2. The formula contained in Section 9(i)(2)(d)(1) and the data to be used therein except for the rail rates.

3.

[CONFIDENTIAL TREATMENT HAS BEEN REQUESTED. ACCORDINGLY, THIS SECTION HAS BEEN OMITTED AND FILED SEPARATELY WITH THE SECURITIES AND EXCHANGE COMMISSION.]

Disclosure of the Confidential Information may be made to the parent company, employees, directors, officers and agents of either party subject to the above confidentiality restriction.

Except as limited by the foregoing, nothing in this Section 21 shall prevent Buyer from discussing any portion of this 1990 Amendment with third parties; nothing in the foregoing shall prevent disclosure of Exhibits N and O to the firms listed on Exhibit M.

If disclosure of Confidential Information is required by law or by regulation or orders of any administrative or judicial body having jurisdiction over Buyer or Seller, as the case may be, or as required for evidentiary purposes in any legal proceeding, the same may be disclosed provided notice thereof is given by one party to the other in advance of any required disclosure to give the other time to oppose such disclosure. The obligations of confidentiality and nondisclosure contained herein shall not apply to this 1990 Amendment or the contents of this 1990 Amendment which through no fault of either party becomes part of the public knowledge. Buyer and Seller's obligation of nondisclosure shall terminate on December 31, 2008 unless this Agreement is earlier terminated in which case such obligation shall terminate upon the expiration of this Agreement.

Buyer and Seller further agree that, as amended by this 1990 Amendment, the Agreement shall remain in full force and effect.

Buyer and Seller have caused this 1990 Amendment to the Agreement to be executed, each by its authorized representative.

THUNDER BASIN COAL COMPANY

By___________________________

Its__________________________

Date:________________________

Attest:______________________________

OKLAHOMA GAS & ELECTRIC COMPANY

By___________________________

Its__________________________

Date:________________________

Attest:______________________________

EXHIBIT 10.08

AMENDED AND RESTATED

STOCK EQUIVALENT AND DEFERRED COMPENSATION PLAN

FOR DIRECTORS OF OKLAHOMA GAS AND ELECTRIC COMPANY

ARTICLE I.

PURPOSES, DEFINITIONS AND GENERAL PROVISIONS

1.1. Purposes.

The purposes of this Plan are: (i) to cause a portion of the compensation of each non-employee director of Oklahoma Gas and Electric Company to be paid in equivalents of common stock of the Company and (ii) to offer such non-employee members the opportunity to defer receipt of the balance of their directors' compensation, under terms advantageous to both the director and the Company, until termination of the director's service with the Company.

1.2. Definitions.

(a) "Award" shall mean the amount, expressed either in dollars of Compensation or in Stock Equivalents, that the Board determines pursuant to Section 1.4 hereof will be paid to a Participant on an Award Date.

(b) "Award Date" shall mean the date an Award is to be received by a Participant.

(c) "Board" shall mean the Board of Directors of the Company.

(d) "Beneficiary" shall mean the person or persons (including, without limitation, the trustees of any testamentary or inter vivos trust) designated from time to time in writing by a Participant to receive payments under the Plan after the death of such Participant, or, in the absence of any such designation or in the event that such designated persons or person shall predecease such Participant, or shall not be in existence or shall otherwise be unable to receive such payments, the person or persons designated under such Director's last will and testament or, in the absence of such designation, to the Participant's estate; provided, that the term "Beneficiary" shall mean the person or persons designated under the rules of the insurance company in the case of an insurance policy acquired pursuant to Article III hereof.

(e) "Committee" shall mean those management members of the Company, namely the Chairman of the Board, President, Chief Financial Officer and Corporate Secretary, who administer the Plan, provided all such persons are not eligible to participate in the Plan. All decisions by the Committee shall be by simple majority and the decisions will be final.

(f) "Company" shall mean Oklahoma Gas and Electric Company, an Oklahoma corporation, and any successor thereof.

(g) "Compensation" shall mean payments which the Director receives from the Company for services as a member of its Board of Directors. Such payments may include directors' retainers, board meeting fees and committee meeting fees, but shall exclude direct reimbursement of expenses.

(h) "Deferred Amount" shall mean an amount of Compensation deferred at the election of the Participant under this Plan.

(i) "Director" shall mean any member of the Board of Directors of the Company who is not an employee of the Company.

(j) "Dollar Account" shall mean the bookkeeping account to which a Participant has Deferred Amounts credited under Section 2.2 of this Plan to earn interest as provided therein.

(k) "OG&E Stock" shall mean the common stock of the Company, par value $2.50 per share.

(l) "Participant" shall mean any Director who receives an Award or who elects to defer Compensation pursuant to this Plan.

(m) "Plan" shall mean the Amended and Restated Stock Equivalent and Deferred Compensation Plan for Directors of the Company, as from time to time amended and in effect.

(n) "Stock Account" shall mean the bookkeeping account to which a Participant has Awards and Deferred Amounts credited under Section 2.2 of this Plan with Stock Equivalents as provided therein.

(o) "Stock Equivalents" shall mean the units, representing a like number of shares of OG&E stock, that are credited to a Director's Stock Account under Section 2.2 of this Plan.

(p) "Termination of Service" shall mean the termination (by death, retirement or otherwise) of a Participant's service as a Director of the Company.

1.3. Deferral Of Compensation.

Each Director may elect to have all or a portion of his Compensation for any calendar year deferred under this Plan. Such election shall be executed in writing by the Director and filed with the Secretary of the Company, prior to the beginning of the calendar year during which such Compensation is earned, on a form prescribed by the Company. The election may specify that the Participant desires to have all or a specified percentage of his Compensation (other than any portion subject to an Award) for the year deferred under the Plan. The election shall specify which portion or portions of such Deferred Amount shall be allocated between Article II and Article III hereof, subject to the following:

(a) An election to treat all or any portion of a Deferred Amount as being governed under Article II hereof shall designate the portion or portions to be credited to the Participant's Dollar Account and/or Stock Account governed under that Article, and shall be irrevocable for the first calendar year to which such election relates, and it shall continue in effect for subsequent calendar years until changed prospectively by the Participant before the beginning of the calendar year for which the change is effective; subject, however, in each instance to the provisions in the last paragraph of Section 2.2 and provided, further, that a Participant subsequently may elect in accordance with Section 2.3 to transfer all or part of his Dollar Account Balance to a Stock Account.

(b) An election to treat all or any portion of a Deferred Amount as being governed under Article III hereof shall be irrevocable at all times until the Director's Termination of Service.

1.4. Awards.

The amount and number of Awards that may be granted under this Plan is subject to the sole discretion of the Board and shall be determined in the sole discretion of the Board. Each Award shall contain such terms, restrictions and conditions as the Board may determine that are not inconsistent with this Plan, provided that Awards shall be payable to a Participant only in cash and, subject to Section 2.5 hereof, only upon a Participant's Termination of Service. Awards shall be made either in Stock Equivalents or as a dollar amount of Compensation, as determined in the sole discretion of the Board.

ARTICLE II.

AWARDS AND STRAIGHT CASH DEFERRED COMPENSATION

2.1. General.

To the extent a Director receives an Award pursuant to Section 1.4 hereof, such Award shall be subject to the following provisions of this Article. To the extent that a Director elects to treat any portion of his Deferred Amount as being governed under this Article II, then the following provisions under this Article also shall be applicable with respect to such portion of his Deferred Amount. References to "Deferred Amount" under this Article II shall mean that portion of the Deferred Amount which the Director elects to be governed under this Article.

2.2. Treatment Of Deferred Amounts and Awards.

The Company shall establish on its books the necessary bookkeeping accounts to accurately reflect the Company's liability to each Participant who has deferred Compensation under this Article or who has received an Award pursuant to Section 1.4. To these accounts shall be credited Awards and Deferred Amounts, plus increments as described hereafter. Payments to the Participant or his Beneficiary following Termination of Service shall be debited to the accounts. In addition, debits and credits to the accounts shall be made in the manner provided in Section 2.3 and in the last paragraph of this Section 2.2 in the event of a transfer pursuant to Section 2.3 or pursuant to the last paragraph of this Section 2.2. The standing balance in each account is hereafter referred to as the "Account Balance." Despite the maintenance of such bookkeeping accounts, the Company's obligation to make payments under the Plan shall be made from the Company's general assets and property. The Company may, in its sole discretion, establish a separate fund or account to make payment of benefits to a Participant or his Beneficiary or Beneficiaries hereunder. Whether or not the Company, in its sole discretion, does establish such a fund or account, no Participant, his Beneficiary or Beneficiaries or any person shall have, under any circumstances, any interest whatever in any particular property or assets of the Company by virtue of this Plan.

A Participant who has elected to defer Compensation under this Article shall direct on the deferral election made pursuant to Section 1.3 that the Deferred Amount be credited to a Dollar Account or a Stock Account, or partially to one Account and partially to the other Account, on the same date that it would otherwise be payable to him. Such Deferred Amounts and any Awards shall also be subject to the following terms and conditions:

(a) Dollar Account. Deferred Amounts credited to this Account shall accrue interest from the date of credit to the date of transfer in accordance with Section 2.3, or to the date of payment in accordance with Section 2.4 or Section 2.5, at a variable rate of interest determined quarterly on a prospective basis. Interest shall be credited as of the end of each calendar quarter and, in the event of a transfer in accordance with Section 2.3 or a payment in accordance with Section 2.4 or Section 2.5, as of the close of business on the day immediately preceding the date of such transfer or payment. The interest rate for each quarter shall be equivalent to the one month commercial paper rate quoted by Salomon Brothers in its Bond Market Roundup, or by such other recognized source as the Company may designate, for the week in which the preceding calendar quarter ends.

(b) Stock Account. Awards in the form of Stock Equivalents shall be credited to this Account. Awards expessed in dollars of Compensation also shall be credited to this Account and shall be converted into Stock Equivalents equal to the number of shares of OG&E stock, to three decimal places, that could be purchased on the Award

Date with the dollar amount of such Award, at a price per share equal to the arithmetical mean of the highest and lowest quoted selling prices on the New York Stock Exchange Composite Tape for such day. If there are no sales on that day, then such mean on the next preceding day on which there are such sales shall be used.

Deferred Amounts credited to this Account shall be converted into Stock Equivalents equal to that portion of the Deferred Amount which the Participant elected to have so credited. The Stock Equivalents shall be equal to the number of shares of OG&E stock, to three decimal places, that could be purchased on the day that such portion of the Participant's Deferred Amount would otherwise be paid, at a per share price equal to the arithmetical mean of the highest and lowest quoted selling prices on the New York Stock Exchange Composite Tape for such day. If there are no sales on that day, then such mean on the next preceding day on which there are such sales shall be used.

A Participant who has a Deferred Amount governed by the terms of Article II of this Plan, as in effect prior to its amendment and restatement as of December 1, 1989, shall have his Account Balance as of December 1, 1989, transferred to a Dollar Account; provided, however, that the Participant may file a written election with the Secretary of the Company on or before December 31, 1989, to have part or all of his Dollar Account Balance as of January 31, 1990, transferred to a Stock Account. The transfer shall be on the basis described in Section 2.3. Either or both of such accounts shall thereafter be governed by the terms of this Plan.

On each date on which a dividend in cash or property is distributed on shares of issued and outstanding OG&E stock, the Stock Account of a Participant shall be credited with a number of Stock Equivalents based upon the amount of cash or the fair market value of any property (the "base amount") distributed with respect to a number of shares of issued and outstanding OG&E stock equal to the number of Stock Equivalents (including fractions) standing to the Participant's credit in his Stock Account on the record date for such distribution (assuming that fractional shares could be held of record and that distributions were made with respect thereto). The number of Stock Equivalents to be so credited shall be equal to the number of shares of OG&E stock, to three decimal places, that could be purchased on such dividend distribution date with the base amount at a per share price equal to the mean between the highest and lowest selling prices on the New York Stock Exchange Composite Tape for that day. If there are no sales on that day, then such mean on the next preceding day on which there are such sales shall be used.

On each date on which a stock dividend or stock split is distributed on shares of OG&E stock, a Participant's Stock Account shall be credited with a number of Stock Equivalents equal to the number of shares which would have been distributed with respect to a number of shares of issued and outstanding OG&E stock equal to the number of Stock Equivalents (including fractions) standing to the Participant's credit in his Stock Account on the record date for such distribution (assuming that fractional shares could be held of record and that fractional shares would be distributed).

In the event that the Company shall be a party to any consolidation or merger or share exchange and, in connection with such transaction, all or part of the outstanding shares of OG&E stock shall be changed into or exchanged for stock or other securities of any other entity or of the Company or cash or any other property, then the Account Balance in a Participant's Stock Account shall be transferred on the day immediately preceding the effective date of such transaction to a Dollar Account for the Participant, with the Participant's Stock Account being debited with the number of Stock Equivalents in the Stock Account immediately prior to the transfer and the Participant's Dollar Account being credited with an amount equal to the number of Stock Equivalents in the Participant's Stock Account immediately prior to such transfer multiplied by the mean between the highest and lowest selling prices for OG&E stock on the New York Stock Exchange Composite Tape on the date of such transfer or, if there are no sales on such day, such mean on the next preceding date on

which there are such sales. Following such event, no additional amounts shall be credited to the Stock Account and all future Deferred Amounts that were to be credited to a Stock Account shall be credited to a Dollar Account, until changed by the Participant pursuant to Section 1.3.

2.3. Transfers From Dollar Accounts To Stock Accounts.

Each Participant may elect, on an annual basis, to have all or a portion of his Dollar Account transferred to a Stock Account. Such election shall be executed in writing by the Participant and filed with the Secretary of the Company prior to December 31 of a calendar year to be effective as of the close of business on January 31 of the succeeding calendar year. The

Participant's Dollar Account shall be debited with the amount so transferred from such account to the Participant's Stock Account. The number of Stock Equivalents to be credited to the Participant's Stock Account shall be determined by dividing the amount to be transferred from the Participant's Dollar Account by a per share price equal to the mean of highest and lowest quoted selling prices of OG&E stock on the New York Stock Exchange Composite Tape for the January 31 date of transfer. If there are no sales on that day, then such mean on the next preceding day on which there are such sales shall be used. Transfers from a Participant's Stock Account to a Dollar Account shall not be permitted, except as provided in the last paragraph of Section 2.2 hereof.

2.4. Payment Of Awards and Deferred Amounts.

Upon Termination of Service, a Participant's aggregate Account Balances in his Dollar Account and Stock Account under this Article shall be paid to the Participant (or, in the event of Particpant's death, his Beneficiary) in such number of annual installments (not exceeding 5), as shall be determined by the Committee in its sole discretion. The Committee may consult with the Participant prior to such determination, but the Committee will not be obligated by the desires of the Participant. Such payments shall commence not later than one year after Termination of Service and shall be made in cash out of the general assets and property of the Company. Regardless of when Termination of Service occurs, however, no payment of a Participant's Dollar Account and Stock Account Balances may commence until the Participant has attained age 50. In converting a Participant's Stock Equivalents in his Stock Account into cash for payment purposes, such conversion shall be made on each payment date to such Participant based on the then current value of the shares of OG&E stock reflected in his Stock Account. For purposes of the preceding sentence, value shall be determined based upon the mean between the highest and lowest selling prices for OG&E stock on the New York Stock Exchange Composite Tape on the date immediately preceding the payment date. If there are no sales on that day, then such mean on the next preceding day on which there are such sales shall be used.

2.5. Acceleration Of Payments.

The Committee, within its sole discretion, is empowered to accelerate the payment of a Participant's Dollar Account Balance or Stock Account Balance to such Participant or his Beneficiary, whether before or after the Participant's Termination of Service, for good and substantial reasons, such as the Participant's death, disability, hardship or other adverse need, changes in the tax laws or accounting principles adversely affecting the Plan and its effect on the Company, the Participants or their Beneficiaries, or other similar reasons acceptable to the Committee; except that, prior to a Participant's Termination of Service, the Committee may accelerate the payment of all or part of a Participant's Stock Account Balance only upon the Participant's disability.

ARTICLE III.

CASH DEFERRED COMPENSATION/SPLIT DOLLAR INSURANCE

3.1. General.

To the extent that a Director elects to treat any portion of his Deferred Amount as being governed under this Article III, then the following provisions under this Article shall be applicable with respect to such Deferred Amount. References to "Deferred Amount" under this Article III shall mean that portion of the Deferred Amount which the Director elects to be governed under this Article.

3.2. Insurance Policy.

After consulting with a Participant, the Committee, on behalf of the Company, shall obtain a premium policy or policies of insurance on the life of the Participant (the "Policy"), and enter into an appropriate agreement with the insurance company, the terms of which Policy and agreement shall be based upon those the Committee deems advisable, within its sole discretion, subject, however, to the following provisions prior to the time the Participant has a Termination of Service.

(a) All premiums due on the Policy shall be paid by the Company from the Deferred Amount, but shall in no event exceed the Participant's Deferred Amount.

(b) In the event of the death of the Participant, the Company, its successors or assigns, shall be entitled to receive from the life insurance proceeds under the Policy an amount equal to the premiums, without interest thereon, the Company has paid.

(c) Any portion of the death proceeds which is in excess of the amount payable to the Company, its successors or assigns, shall be payable to the person or persons entitled thereto under the Policy.

3.3. Ownership Of Policy.

The Policy may reserve to the Participant, or his assignee, the sole right to change the Beneficiaries for any amount payable thereunder in the event of the Participant's death, but, notwithstanding anything herein to the contrary, each and every other right of ownership of such Policy shall be reserved solely to, and be absolutely vested in, the Company.

3.4. Possession Of Policy.

The Company shall keep possession of the Policy.

3.5. Deferred Compensation At Death.

In the event that the Participant dies before a Termination of Service, the Company agrees to pay, out of the general assets of the Company, to the deceased Participant's Beneficiary an amount of deferred compensation equal to the amount received by the Company under subparagraph (b) of Section 3.2 hereof. Such amount may be paid in the manner

set forth in Sections 2.4 and 2.5 hereof; provided, the Committee may pay such amount in a lump sum without the consent of the Participant.

3.6. Deferred Compensation At Termination Of Service.

Upon the Participant's Termination of Service for any reason other than his death, the Company agrees to pay, out of the general assets of the Company, to the Participant an amount of deferred compensation equal to the then cash value of the Policy on his life. Such amounts may be paid in the manner set forth in Sections 2.4 and 2.5 hereof; provided, the Committee may pay such amount in a lump sum without the consent of the Participant. Provided further, the Committee may, without the consent of the Participant, assign and distribute such Policy to the Participant in full satisfaction of the Company's liability under this Article III.

ARTICLE IV.

OTHER PROVISIONS

4.1. Amendment Or Termination.

The Board of Directors may amend or terminate this Plan at any time; provided, however, that no amendment or termination shall adversely affect any prior Awards or then existing Deferred Amounts or rights under this Plan, and provided further that no amendment may be made to the last sentence of Section 4.5 hereof.

4.2. Expenses.

The expenses of administering the Plan shall be borne by the Company, and shall not be charged against any Participant's Awards or Deferred Amounts; provided, however, that any commissions on premium payments under any Policy issued pursuant to Article III hereof shall not be considered an expense to be borne by the Company.

4.3. Applicable Law.

The provisions of the Plan shall be construed, administered and enforced according to the laws of the State of Oklahoma.

4.4. No Trust.

No action by the Company or its Board of Directors under this Plan shall be construed as creating a trust, escrow or other secured or segregated fund or other fiduciary relationship of any kind in favor of any Participant, his Beneficiary, or any other persons otherwise entitled to his Awards or Deferred Amounts nor, shall any of said persons have rights under any agreement or Policy in connection therewith between the Company and the insurance company, except the right to designate a Beneficiary of the proceeds of a Policy upon the death of the Participant as provided herein. The status of the Participant and his Beneficiary with respect to any liabilities assumed by the Company hereunder shall be solely those of unsecured creditors of the Company. Any Policy or any other asset acquired or held by the Company in connection with liabilities assumed by it hereunder, shall not be deemed to be held under any trust, escrow or other secured or segregated

fund or other fiduciary relationship of any kind for the benefit of the Participant or his Beneficiaries or to be security for the performance of the obligations of the Company, but shall be, and remain, a general, unpledged, unrestricted asset of the Company at all times subject to the claims of general creditors of the Company.

4.5. No Assignability And Successors.

Neither the Participant nor any other person shall acquire any right to or interest in any amount awarded to the Participant, otherwise than by actual payment in accordance with the provisions of this Plan, or have any power, voluntarily or involuntarily, to transfer, assign, anticipate, pledge, mortgage or otherwise encumber, alienate or transfer any rights hereunder in advance of any of the payments to be made pursuant to this Plan or any portion thereof. With respect to a Policy issued pursuant to Article III hereof, neither the Participant nor his spouse nor any Beneficiary, shall have any rights to transfer, assign, anticipate, pledge, mortgage or otherwise encumber, alienate or transfer any rights hereunder in advance of any right to receive any payments under the Policy, which payments and the rights thereto are hereby expressly declared to be non-assignable and non-transferable. The obligations of the Company hereunder shall be binding upon any and all successors and assigns to the Company.

4.6. Withholding.

The Company shall comply with all federal and state laws and regulations respecting the withholding, deposit and payment of any income or employment taxes relating to the payment of Awards or Deferred Amounts under this Plan.

4.7. No Impact On Directorship.

This Plan shall not be construed to confer any right on the part of a Participant to be or remain a Director or to receive any, or any particular rate of, Compensation.

4.8. Interpretations.

Interpretations of, and determinations related to, this Plan made by the Company in good faith, including any determinations or calculations of Awards, Deferred Amounts or Account Balances, shall be conclusive and binding upon all parties; and the Company and the members of the Committee shall not incur any liability to a Participant for any such interpretation or determination so made or for any other action taken by it in connection with this Plan.

4.9. Effective Date.

This Plan, as amended and restated, shall be effective from and after November 30, 1994.

OKLAHOMA GAS AND ELECTRIC COMPANY

By: ___________________________
J. G. Harlow, Jr.
Chairman of the Board and
President

Exhibit 23.01

CONSENT OF INDEPENDENT PUBLIC ACCOUNTANTS

As independent public accountants, we hereby consent to the incorporation of our reports dated January 26, 1995 included in the Oklahoma Gas and Electric Company Form 10-K for the year ended December 31, 1994, into the previously filed Post-Effective Amendment No. One to Form S-3 Registration Statement No. 33-32870, Form S-8 Registration Statement No. 33-35833, Post-Effective Amendment No. Three to Form S-3 Registration Statement No. 2-94973, and Form S-8 Registration Statement No. 33-52169.

/s/ ARTHUR ANDERSEN LLP
ARTHUR ANDERSEN LLP

Oklahoma City, Oklahoma,
March 28, 1995

EXHIBIT 24.01

POWER OF ATTORNEY

WHEREAS, OKLAHOMA GAS AND ELECTRIC COMPANY, 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, 1994; 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 J. G. HARLOW, JR., A. M. STRECKER and D. L. YOUNG, 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 18th day of January, 1995.

J. G. Harlow, Jr., Chairman and President, Principal Executive Officer and Director	/s/ J. G. Harlow, Jr.
Herbert H. Champlin, Director	/s/ Herbert H. Champlin
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
John F. Snodgrass, Director	/s/ John F. Snodgrass
Bill Swisher, Director	/s/ Bill Swisher
John A. Taylor, Director	/s/ John A. Taylor
Ronald H. White, M.D., Director	/s/ Ronald H. White, M.D.
A. M. Strecker, Principal Financial Officer	/s/ A. M. Strecker
D. L. Young, Principal Accounting Officer	/s/ D. L. Young

STATE OF OKLAHOMA)
)SS
COUNTY OF OKLAHOMA)

On the date indicated above, before me, Lisa Thompson, Notary Public in and for said County and State, personally appeared the above named directors and officers of OKLAHOMA GAS AND ELECTRIC COMPANY, 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 18th day of January, 1995.

/s/ LISA THOMPSON
Lisa Thompson
Notary Public in and for the County
of Oklahoma, State of Oklahoma

My Commission Expires:
January 16, 1996

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This schedule contains summary financial information extracted from the Oklahoma Gas and Electric Company Consolidated Statements of Income, Balance sheets, and Statements of Cash Flow as, reported on Form 10-K as of December 31, 1994 and is qualified in its entirety by reference to such Form 10-K.
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Exhibit 99.01

SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 11-K
ANNUAL REPORT

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

OR

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

For the fiscal year ended december 31, 1994   Commission File Number 1-1097

OKLAHOMA GAS AND ELECTRIC COMPANY
EMPLOYEES' RETIREMENT SAVINGS PLAN

(Full Title of the Plan)

OKLAHOMA GAS AND ELECTRIC COMPANY
101 North Robinson
P.O. Box 321
Oklahoma City, Oklahoma 73101-0321

(Name of issuer of the securities held pursuant to the Plan and the Address of its principal executive office)

SIGNATURES

The undersigned consist of the members of the Committee having the responsibility for the administration of the Oklahoma Gas and Electric Company Employees' Retirement Savings Plan. Pursuant to the requirements of the Securities Exchange Act of 1934, the Plan has duly caused this Annual Report on Form 11-k to be signed on its behalf by the undersigned, thereunto duly authorized, in the City of Oklahoma City and State of Oklahoma on the 29th day of March 1995.

OKLAHOMA GAS AND ELECTRIC COMPANY
EMPLOYEES' RETIREMENT SAVINGS PLAN

By /s/ IRMA B. ELLIOTT

Irma B. Elliott
Chairperson

By /s/ DONALD R. ROWLETT

Donald R. Rowlett
Member

By /s/ R. P. SCHMID

R.P. Schmid
Member

Exhibit 99.02

OKLAHOMA GAS AND ELECTRIC COMPANY
DESCRIPTION OF COMMON STOCK

The following statements are summaries of certain provisions of the Restated Certificate of Incorporation of Oklahoma Gas and Electric Company (the "Company") and are subject to the detailed provisions thereof. Such summaries do not purport to be complete, and reference is made to the Company's Restated Certificate of Incorporation (which is filed as Exhibit 4.01 to the Company's Post-Effective Amendment No. Three to Registration Statement No. 2-94973) for a full and complete statement of such provisions. The term "preferred stock" as used herein means the Company's authorized shares of 4% Cumulative Preferred Stock, par value $20 per share, its Cumulative Preferred Stock, par value $100 per share, and its Cumulative Preferred Stock, par value $25 per share.

DIVIDEND RIGHTS

After dividends on all classes and series of preferred stock have been paid (or declared and set apart for payment) for all past dividend periods and declared for the current dividend period, at the full rates fixed therefor, dividends may be declared and paid on the Common Stock subject to the restrictions set forth under the following subcaption.

LIMITATIONS ON PAYMENT OF DIVIDENDS ON COMMON STOCK

Unless the capital represented by the Common Stock (including premiums on capital stock and retained earnings accounts) is 25% or more of total capital (which also includes debt maturing more than one year after date of issue), dividends (other than dividends payable in Common Stock) or distributions on, or acquisitions for value of, Common Stock may not exceed 75% of net income for the preceding twelve-month period after deducting dividends accruing on preferred stock during the period; and if less than 20%, may not exceed 50% of such net income. No portion of the retained earnings of the Company is presently restricted by this provision. The Restated Certificate of Incorporation further provides that no dividend may be declared or paid on the Common Stock until all amounts required to be paid or set aside for any sinking fund for the redemption or purchase of Cumulative Preferred Stock, par value $25 per share, have been paid or set aside. Currently, no shares of Cumulative Preferred Stock, par value $25 per share, are outstanding.

The Indenture, as supplemented, which secures the First Mortgage Bonds of the Company, contains provisions providing that, so long as any Bonds are outstanding, earned surplus (i.e., retained earnings) equal to the sum of (1) the amount by which the aggregate of (a) provisions for retirement and depreciation and (b) expenditures for maintenance, during the period from June 1, 1955, to the last date for which a statement of income is available, is less than 15% of gross operating revenues (after deducting cost of electricity purchased for resale, rentals paid for utility property and the portion of gross operating revenues attributable to increases since January 6, 1975, in the Company's cost of fuel used in electric generation) for that period and (2) the amount, if any, by which all of the consideration paid by the Company in acquiring shares of its Common Stock during the above period exceeds $217,301,128 plus any consideration received by the Company from the sale after September 30, 1991 of its Common Stock, shall not be available for the payment of cash dividends on Common Stock; and that the Company shall not acquire shares of its Common Stock for a valuable consideration if after such acquisition the sum of (1) and (2) above would exceed its then earned surplus (retained earnings). These provisions are not expected to affect adversely the Company's ability to pay dividends during the foreseeable future.

VOTING RIGHTS

Each holder of Common Stock and each holder of 4% Cumulative Preferred

Stock is entitled at all meetings of shareowners to one vote for each $2.50 of par value of such stock held. The holders of Cumulative Preferred Stock, par value $100 per share, and Cumulative Preferred Stock, par value $25 per share, are not entitled to any voting rights whatsoever, except as set forth below and as expressly provided by law.

If and when dividends payable on the 4% Cumulative Preferred Stock shall be in default in an amount equivalent to four full quarter-yearly dividends and thereafter until all defaults shall have been paid, the holders of the 4% Cumulative Preferred Stock, voting separately as one class, will be entitled to elect the smallest number of directors necessary to constitute a majority of the Board of Directors, and the holders of the Common Stock, voting separately as a class, will be entitled to elect the remaining directors of the Company. This special voting right shall become vested in the holders of all classes and series of preferred stock, as one class, if at any time there shall be no shares of 4% Cumulative Preferred Stock outstanding.

The consent or affirmative vote of the holders of at least two-thirds of the outstanding shares of 4% Cumulative Preferred Stock is required to: (a) authorize or issue stock ranking prior thereto; (b) adversely change the terms and provisions of the 4% Cumulative Preferred Stock; (c) issue shares of 4% Cumulative Preferred Stock or of stock ranking pari passu with it as to dividends or liquidation rights unless in exchange for or to retire an equal number of shares of such stocks or unless specified income and capital ratio requirements are met. Similar provisions applicable to each class of the Cumulative Preferred Stock are also contained in the Restated Certificate of Incorporation. The vote or consent of the holders of at least a majority of the Common Stock is required to amend Article VII of the Restated Certificate of Incorporation, which sets forth the classes, authorized amounts, and certain of the terms and provisions of the stocks of the Company.

The consent or affirmative vote of the holders of at least a majority of the outstanding shares of the 4% Cumulative Preferred Stock and of each class of the Cumulative Preferred Stock is required under specified conditions for the issuance of securities representing unsecured indebtedness or in case of merger or consolidation. The Company's Restated Certificate of Incorporation also contains "fair price" provisions, which require the approval by the holders of at least 80% of the voting power of the Company's outstanding Voting Stock (as defined below) as a condition for mergers, consolidations, sales of substantial assets, issuances of capital stock and certain other business combinations and transactions involving the Company and any substantial (10% or more) holder of the Company's Voting Stock unless the transaction is either approved by a majority of the members of the Company's Board of Directors who are unaffiliated with the substantial holder or certain minimum price and procedural requirements are met. The provisions summarized in the foregoing sentence may be amended only by the approval of the holders of at least 80% of the voting power of the Company's outstanding Voting Stock. The Company's Voting Stock consists of all outstanding shares of the Company entitled to vote generally in the election of directors and currently consists of the Common Stock and 4% Cumulative Preferred Stock.

The Voting Stock of the Company does not have cumulative voting rights for the election of directors. Subject to the rights described above of the holders of the 4% Cumulative Preferred Stock to elect directors under certain circumstances, the Company's Restated Certificate of Incorporation and By-Laws contain provisions stating that: (1) the Board of Directors shall be divided into three classes as nearly equal in number as possible with staggered terms of office so that only approximately one-third of the directors are elected at each annual meeting of shareowners; (2) directors may be removed only with the approval of the holders of at least 80% of the voting power of the shares of the Company generally entitled to vote; (3) any vacancy on the Board of Directors shall be filled only by the remaining directors then in office, though less than a quorum; (4) advance notice of introduction by shareowners of business at annual shareowner meetings and of shareowner nominations for the election of directors shall be given and that certain information be provided with respect to such matters; (5) shareowner action may be taken only at an annual meeting of shareowners or a special meeting of shareowners called by the President or the Board of Directors; and (6) the foregoing provisions may be amended only by the approval of the holders of at least 80% of the voting power of the shares generally entitled to vote. These provisions, along with the "fair price" provisions discussed above, would make more difficult a change in control of the Company that is opposed by the Company's Board of Directors.

LIQUIDATION RIGHTS

In case of voluntary liquidation, dissolution or winding up of the Company, the holders of the preferred stock are entitled, respectively, to be paid the amounts which they would be entitled to receive if, on the date of such action, the respective shares of the preferred stock held by them had been redeemed by the Company. In case of an involuntary liquidation, dissolution or winding up of the Company, the holders of the preferred stock are entitled to be paid an amount equal to the par value of their respective shares plus the accrued dividends thereon to the date of payment. Thereafter, the holders of the Common Stock are entitled to receive the remaining assets and funds pro rata, according to the number of shares of Common Stock held.

OTHER PROVISIONS

The Board of Directors may allot and issue shares of Common Stock for such consideration, not less than the par value thereof, as it may from time to time determine. In addition, subject to certain limitations in the Restated Certificate of Incorporation, the Board of Directors may issue additional series of each class of Cumulative Preferred Stock with such dividend rates and redemption provisions (including, in the case of the Cumulative Preferred Stock, par value $25 per share, sinking funds) as the Board of Directors may determine. No holder of Common Stock has the preemptive right to subscribe for or purchase any part of any new or additional issue of stock or securities convertible into stock. The Common Stock of the Company is not subject to further calls or to assessment by the Company.

RIGHTS TO PURCHASE SERIES A CUMULATIVE PREFERRED STOCK

On December 11, 1990, the Board of Directors of the Company declared a dividend of one preferred stock purchase right (a "Right" or "Rights") for each outstanding share of Common Stock of the Company. The dividend was paid on December 31, 1990 (the "Record Date"), to shareowners of record as of such Record Date. If and when the Rights become exercisable, each Right will entitle the holder of record to purchase from the Company one one-hundredth of a share of Series A Cumulative Preferred Stock, par value $25 per share ("Series A Preferred Stock") of the Company, at a price of $95 per one one-hundredth of a share (the "Purchase Price"), although the price may be adjusted as described below. The description and terms of the Rights are set forth in a Rights Agreement (the "Rights Agreement") between the Company and The Liberty National Bank and Trust Company of Oklahoma City, as Rights Agent (the "Rights Agent").

Initially, (i) the Rights will not be exercisable, (ii) certificates will not be sent to shareowners, (iii) the Rights will be evidenced by the Common Stock certificates, (iv) the Rights will automatically trade with the Common Stock, (v) the Rights and will be transferred with and only with such Common Stock certificates, (vi) new Common Stock certificates will contain a notation incorporating the Rights Agreement by reference and (vii) the surrender for transfer of any certificates for Common Stock outstanding will also constitute the transfer of the Rights associated with the Common Stock represented by such certificate.

Separate certificates representing the Rights will be distributed as soon as practicable after the "Distribution Date," which is the close of business on the earlier to occur on the tenth day following:

(i) a public announcement (or, if earlier, the date a majority of the Board of Directors of the Company becomes aware) that a person or group of affiliated or associated persons acquired, or obtained the right to acquire, beneficial ownership of Common Stock or other securities of the Company representing 20% or more of the voting power of all securities of the Company then outstanding generally entitled to vote for the election of directors ("Voting Power") (such person or group being called an "Acquiring Person" and such date of first public announcement being called the "Stock Acquisition Date"), or

(ii) the commencement of, or public announcement of an intention to commence, a tender or exchange offer the consummation of which would result in the ownership of 20% or more of the outstanding Voting Power (the earlier of the dates in clause (i) or (ii) being called the "Distribution Date").

As soon as practicable following the Distribution Date, separate certificates evidencing the Rights ("Right Certificates") will be mailed to holders of record of the Company's Common Stock as of the close of business on the Distribution Date, and such separate certificates alone will evidence the Rights from and after the Distribution Date.

Even if they have acquired, or obtained the right to acquire, beneficial ownership of 20% or more of the Voting Power of the Company, each of the following persons (an "Exempt Person") will not be deemed to be an Acquiring Person: (i) the Company, any subsidiary of the Company, any employee benefit plan or employee stock plan of the Company or of any subsidiary of the Company; and (ii) any person who becomes an Acquiring Person solely by virtue of a reduction in the number of outstanding shares of Common Stock, unless and until such person shall become the beneficial owner of, or make a tender offer for any additional shares of Common Stock.

The holders of the Rights are not required to take any action until the Rights become exercisable. The Rights are not exercisable until the Distribution Date. The Rights will expire at the close of business on December 11, 2000, unless earlier redeemed or exchanged by the Company as described below.

In order to protect the value of the Rights to the holders, the Purchase Price and the number of shares of Series A Preferred Stock (or other securities or property) issuable upon exercise of the Rights are subject to adjustment from time to time (i) in the event of a stock dividend on, or a subdivision, combination or reclassification of, the Company's Common Stock or Series A Preferred Stock, (ii) upon the grant to holders of the Series A Preferred Stock of certain rights or warrants to subscribe for Series A Preferred Stock or convertible securities at less than the current market price of the Series A Preferred Stock or (iii) upon the distribution to holders of the Series A Preferred Stock of evidences of indebtedness or assets (excluding dividends payable in Series A Preferred Stock) or of subscription rights or warrants (other than those referred to above).

These adjustments are called anti-dilution provisions and are intended to ensure that a holder of Rights will not be adversely affected by the occurrence of such events. With certain exceptions, the Company is not required to adjust the Purchase Price until cumulative adjustments require a change of at least 1% in the Purchase Price.

In the event (i) any Person (other than an Exempt Person) becomes an Acquiring Person (except pursuant to an offer for all outstanding shares of Common Stock that the independent directors determine prior to the time such offer is made to be fair to and otherwise in the best interest of the Company and its shareowners) or (ii) any Exempt Person who is the beneficial owner of 20% or more of the outstanding Voting Power of the Company fails to continue to qualify as an Exempt Person, then each holder of record of a Right, other than the Acquiring Person, will thereafter have the right to receive, upon payment of the Purchase Price, Common Stock (or, in certain circumstance, cash, property or other securities of the Company) having a market value at the time of the transaction equal to twice the Purchase Price. Rights are not exercisable following such event, however, until such time as the Rights are no longer redeemable by the Company as set forth below. Any Rights that are or were at any time, on or after the Distribution Date, beneficially owned by an Acquiring Person shall become null and void.

For example, at an exercise price of $95 per Right, each Right not owned by an Acquiring Person (or by certain related parties) following an event set forth in the preceding paragraph would entitle its holder to purchase $190 worth of Common Stock (or other consideration, as noted above) for $95. Assuming that the Common Stock had a per share value of $40 at such time, the holder of each valid Right would be entitled to purchase 4.75 shares of Common Stock for $95.

After the Rights have become exercisable, if (i) the Company is acquired in a merger or other business combination (in which any shares of the Company's Common Stock are changed into or exchanged for other securities or assets) or (ii) more than 50% of the assets or earning power of the Company and its subsidiaries (taken as a whole) are sold or transferred in one or a series of related transactions, the Rights Agreement provides that proper provision shall be made so that each holder of record of a Right will have the right to receive, upon payment of the Purchase Price, that number of shares of common stock of the acquiring company having a market value at the time of such transaction equal to two times the Purchase Price.

To the extent that insufficient shares of Common Stock are available for the exercise in full of the Rights, holders of Rights will receive upon exercise shares of Common Stock to the extent available and then other securities of the Company, including units of shares of Series A Preferred Stock with rights substantially comparable to those of the Common Stock, property, or cash, in proportions determined by the Company, so that the aggregate value received is equal to twice the Purchase Price. The Company, however, shall not be required to issue any cash, property or debt securities upon exercise of the Rights to the extent their aggregate value would exceed the amount of cash the Company would otherwise be entitled to receive upon exercise in full of the then exercisable Rights.

No fractional shares of Series A Preferred Stock or Common Stock will be required to be issued upon exercise of the Rights and, in lieu thereof, a payment in cash may be made to the holder of such Rights equal to the same fraction of the current market value of a share of Series A Preferred Stock or, if applicable, Common Stock.

At any time until the earlier of (i) ten days after the Stock Acquisition Date (subject to extension by the Board of Directors) or (ii) the date the Rights are exchanged pursuant to the Rights Agreement, the Company may redeem the Rights in whole, but not in part, at a price of $0.01 per Right (the "Redemption Price"). Immediately upon the action of the Board of Directors of the Company authorizing redemption of the Rights, the right to exercise the Rights will terminate, and the only right of the holders of Rights will be to receive the Redemption Price without any interest thereon.

At any time after any Person becomes an Acquiring Person, the Board of Directors may, at its option, exchange all or part of the outstanding Rights (other than Rights held by the Acquiring Person and certain related parties) for shares of Common Stock at an exchange ratio of one share of Common Stock per Right

(subject to certain anti-dilution adjustments). The Board may not effect such an exchange, however, at any time any Person or group owns 50% or more of the Voting Power of the Company. Immediately after the Board orders such an exchange, the right to exercise the Rights shall terminate and the holders of Rights shall thereafter only be entitled to receive shares of Common Stock at the applicable exchange ratio.

Under presently existing federal income tax law, the issuance of the Rights is not taxable to the Company or to shareowners and will not change the way in which shareowners can presently trade the Company's shares of Common Stock. If the Rights should become exercisable, shareowners, depending on then existing circumstances, may recognize taxable income.

The Rights Agreement may be amended by the Board of Directors of the Company. After the Distribution Date, however, the provisions of the Rights Agreement may be amended by the Board only to cure any ambiguity, to make changes which do not adversely affect the interests of holders of Rights (excluding the interests of any Acquiring Person or an affiliate or associate of an Acquiring Person), or to shorten or lengthen any time period under the Rights Agreement; provided, however, that no amendment to adjust the time period governing redemption shall be made at such time as the Rights are not redeemable. In addition, no supplement or amendment may be made which changes the Redemption Price, the final expiration date, the Purchase Price or the number of one one-hundredths of a share of Series A Preferred Stock for which a Right is exercisable, unless at the time of such supplement or amendment there has been no occurrence of a Stock Acquisition Date and such supplement or amendment does not adversely affect the interests of the holders of Right Certificates (other than an Acquiring Person or an associate or affiliate of an Acquiring Person).

Until a right is exercised, the holder, as such, will have no rights as a shareowner of the Company, including, without limitation, the right to vote or to receive dividends.

The Rights may have certain anti-takeover effects. The Rights will cause substantial dilution to a person or group that attempts to acquire the Company on terms not approved by the Board of Directors and, accordingly, will make more difficult a change of control that is opposed by the Company's Board of Directors. However, the Rights should not interfere with a proposed change of control (including a merger or other business combination) approved by a majority of the Board of Directors since the Rights may be redeemed by the Company at $.01 per Right at any time until ten days after the Stock Acquisition Date (subject to extension by the Board of Directors). Thus, the Rights are intended to encourage persons who may seek to acquire control of the Company to initiate such an acquisition through negotiations with the Board of Directors. Nevertheless, the Rights also may discourage a third party from making a partial tender offer or otherwise attempting to obtain a substantial equity position in, or seeking to obtain control of, the Company. To the extent any potential acquirors are deterred by the Rights, the Rights may have the effect of preserving incumbent management in office.

This summary description of the Rights does not purport to be complete and is qualified in its entirety by reference to the Rights Agreement, which is filed as an Exhibit to the Company's Registration Statement on Form 8-B and is incorporated herein by reference.