UNITED STATES
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

For the fiscal year ended December 31, 1993

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

Commission file number 1-3523

WESTERN RESOURCES, INC.
(Exact name of registrant as specified in its charter)

KANSAS	48-0290150
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
818 KANSAS AVENUE, TOPEKA, KANSAS	66612
(Address of Principal Executive Offices)	(Zip Code)

Registrant's telephone number, including area code 913/575-6300

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

Common Stock, $5.00 par value	New York Stock Exchange
(Title of each class)	(Name of each exchange on which registered)

Securities registered pursuant to Section 12(g) of the Act:
Preferred Stock, 4 1/2% Series, $100 par value
(Title of Class)

Indicated by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes x No

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

State the aggregate market value of the voting stock held by nonaffiliates of the registrant. Approximately $1,871,643,000 of Common Stock and $11,545,000 of Preferred Stock (excluding the 4 1/4% Series of Preferred Stock for which there is no readily ascertainable market value) at March 11, 1994.

Indicate the number of shares outstanding of each of the registrant's classes of common stock.

Common Stock, $5.00 par value	61,617,873
(Class)	(Outstanding at March 11, 1994)

Documents Incorporated by Reference:

Part	Document
III	Portions of the Company's Definitive Proxy Statement for the Annual Meeting of Shareholders to be held May 3, 1994.

WESTERN RESOURCES, INC.
FORM 10-K
December 31, 1993

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PART I

ITEM 1. BUSINESS

GENERAL

Western Resources, Inc. (formerly The Kansas Power and Light Company, KPL) is a combination electric and natural gas public utility engaged in the generation, transmission, distribution and sale of electric energy in Kansas and the purchase, transmission, distribution, transportation and sale of natural gas in Kansas, Missouri and Oklahoma. As used herein, the terms "Company and Western Resources" include its wholly-owned subsidiaries, Astra Resources, Inc., Kansas Gas and Electric Company (KG&E) since March 31, 1992, and KPL Funding Corporation (KFC), unless the context otherwise requires. KG&E owns 47 percent of Wolf Creek Nuclear Operating Corporation, the operating company for Wolf Creek Generating Station (Wolf Creek). Corporate headquarters of the Company is located at 818 Kansas Avenue, Topeka, Kansas 66612. At December 31, 1993, the Company had 5,192 employees.

On January 31, 1994, the Company sold substantially all of its Missouri natural gas distribution properties and operations to Southern Union Company (Southern Union). The Company sold the remaining Missouri properties to United Cities Gas Company (United Cities) on February 28, 1994. The properties sold to Southern Union and United Cities are referred to herein as the "Missouri Properties". With the sales the Company is no longer operating as a utility in the State of Missouri.

The portion of the Missouri Properties purchased by Southern Union, were sold for an estimated sale price of $400 million, in cash, based on a calculation as of December 31, 1993. The final sale price will be calculated as of January 31, 1994, within 120 days of closing. Any difference between the estimated and final sale price will be adjusted through a payment to or from the Company.

United Cities purchased the Company's natural gas distribution system in and around the City of Palmyra, Missouri, for $665,000 in cash.

The operating revenues and operating income (unaudited) related to the Missouri Properties approximated $350 million and $21 million representing approximately 18 percent and seven percent, respectively, of the Company's total for 1993, and $299 million and $11 million representing approximately 19 percent and five percent, respectively, of the Company's total for 1992. Net utility plant (unaudited) for the Missouri Properties, at December 31, 1993, approximated $296 million and $272 million at December 31, 1992. This represents approximately seven percent at December 31, 1993, and six percent at December 31, 1992, of the total Company net utility plant. Separate audited financial information was not kept by the Company for the Missouri Properties. This unaudited financial information is based on assumptions and allocations of expenses of the Company as a whole. For additional information see Note 13 of the Notes to Consolidated Financial Statements.

On March 31, 1992, the Company through its wholly-owned subsidiary KCA Corporation (KCA), acquired all of the outstanding common and preferred stock of Kansas Gas and Electric Company for $454 million in cash and 23,479,380 shares of common stock (the Merger). The Company also paid approximately $20 million in costs to complete the Merger. Simultaneously, KCA and Kansas Gas and Electric Company merged and adopted the name of Kansas Gas and Electric Company (KG&E).

Additional information relating to the Merger can be found in Management's Discussion and Analysis of Financial Condition and Results of Operations and Note 3 of Notes to Consolidated Financial Statements.

The following information includes the operations of KG&E since March 31, 1992.

The percentages of Total Operating Revenues and Operating Income Before Income Taxes attributable to the Company's electric and natural gas operations for the past five years were as follows:

	Total Operating Revenues		Operating Income Before Income Taxes	
Year	Electric	Natural Gas	Electric	Natural Gas
1993	58%	42%	85%	15%
1992	57%	43%	89%	11%
1991	41%	59%	84%	16%
1990	40%	60%	85%	15%
1989	40%	60%	81%	19%

The difference between the percentage of electric operating revenues in relation to the percentage of electric operating income as compared to the same percentages for gas operations is due to the Company's level of investment in plant and its fuel costs in each of these segments.

The amount of the Company's plant in service (net of accumulated depreciation) at December 31, for each of the past five years was as follows:

Year	Electric	Natural Gas	Total
		(Thousands of Dollars)	
1993	$3,641,154	$759,619	$4,400,773
1992	3,645,364	696,036	4,341,400
1991	1,080,579	628,751	1,709,330
1990	1,092,548	567,435	1,659,983
1989	1,092,534	511,733	1,604,267

As a regulated utility, the Company does not have direct competition for retail electric service in its certified service area. However, there is competition, based largely on price, from the generation, or potential generation, of electricity by large commercial and industrial customers, and independent power producers.

Electric utilities have been experiencing problems such as controversy over the safety and use of coal and nuclear power plants, compliance with changing environmental requirements, long construction periods required to complete new generating units resulting in high fixed costs for those facilities, difficulties in obtaining timely and adequate rate relief to recover these high fixed costs, uncertainties in predicting future load requirements, competition from independent power producers and cogenerators, and the effects of changing accounting standards.

The problems which most significantly affect the Company are the use, or potential use, of cogeneration or self-generation facilities by large commercial and industrial customers and compliance with environmental requirements. For additional information see Management's Discussion and Analysis and Notes 4 and 5 of the Notes to Consolidated Financial Statements included herein.

Discussion of other factors affecting the Company is set forth in the Notes to Consolidated Financial Statements and Management's Discussion and Analysis included herein.

ELECTRIC OPERATIONS

General. The Company supplies electric energy at retail to approximately 585,000 customers in 462 communities in Kansas. These include Wichita, Topeka, Lawrence, Manhattan, Salina, and Hutchinson. On September 20 1993, the Company completed the purchase of the electric distribution system in DeSoto Kansas. This acquisition added approximately 880 customers to the Company's system. The Company also supplies electric energy at wholesale to the electric distribution systems of 67 communities and 5 rural electric cooperatives. The Company has contracts for the sale, purchase or exchange of electricity with other utilities. The Company also receives a limited amount of electricity through parallel generation.

The Company's electric sales for the last five years were as follows (includes KG&E since March 31, 1992):

	1993	1992	1991	1990	1989
			(Thousands of MWH)		
Residential	4,960	3,842	2,556	2,403	2,248
Commercial	5,100	4,473	3,051	2,952	2,814
Industrial	5,301	4,419	1,947	1,954	1,925
Other	4,628	3,119	1,984*	1,820	2,077
Total	19,989	15,853	9,538*	9,129	9,064

* Includes cumulative effect to January 1, 1991, of change in revenue recognition. The cumulative effect of this change increased electric sales by 256,000 MWH.

The Company's electric revenues for the last five years were as follows (includes KG&E since March 31, 1992):

	1993	1992	1991	1990	1989
			(Thousands of Dollars)		
Residential	$ 384,618	$296,917	$160,831	$152,509	$142,308
Commercial	319,686	271,303	149,152	146,001	139,567
Industrial	261,898	211,593	78,138	79,225	78,267
Other	138,335	103,072	83,718	85,972	92,201
Total	$1,104,537	$882,885	$471,839	$463,707	$452,343

Capacity. The accredited generating capacity of the Company's system is presently 5,184 megawatts (MW). The system comprises interests in 22 fossil fueled steam generating units, one nuclear generating unit (47 percent interest), seven combustion peaking turbines and one diesel generator located at eleven generating stations. Two units of the 22 fossil fueled units have been "mothballed" for future use (see Item 2, Properties).

The Company's 1993 peak system net load occurred on August 16, 1993 and amounted to 3,821 MW. The Company's net generating capacity together with power available from firm interchange and purchase contracts, provided a capacity margin of approximately 23 percent above system peak responsibility at the time of the peak.

The Company and ten companies in Kansas and western Missouri have agreed to provide capacity (including margin), emergency and economy services for each other. This arrangement is called the MOKAN Power Pool. The pool participants also coordinate the planning of electric generating and transmission facilities.

In January 1994, the Company entered into an agreement with Oklahoma Municipal Power Authority (OMPA), whereby, the Company received a prepayment of approximately $41 million for capacity and transmission charges through the year 2013.

Future Capacity. The Company does not contemplate any significant expenditures in connection with construction of any major generating facilities through the turn of the century (see Management's Discussion and Analysis, Liquidity and Capital Resources). Although the Company's management believes, based on current load-growth projections and load management programs, it will maintain adequate capacity margins through 2000, in view of the lead time required to construct large operating facilities, the Company may be required before 2000 to consider whether to reschedule the construction of Jeffrey Energy Center (JEC) Unit 4 or alternatively either build or acquire other capacity.

Fuel Mix. The Company's coal-fired units comprise 3,186 MW of the total 5,184 MW of generating capacity and the Company's nuclear unit provides 533 MW of capacity. Of the remaining 1,465 MW of generating capacity, units that can burn either natural gas or oil account for 1,373 MW, and the remaining units which burn only oil or diesel account for 92 MW (see Item 2, Properties).

During 1993, low sulfur coal was used to produce 79 percent of the Company's electricity. Nuclear produced 17 percent and the remainder was produced from natural gas, oil, or diesel. Based on the Company's estimate of the availability of fuel, coal will continue to be used to produce approximately 78 percent of the Company's electricity and 18 percent from nuclear.

The Company anticipates the fuel mix to fluctuate with the operation of nuclear powered Wolf Creek which operates on an 18-month refueling and maintenance schedule. The 18-month schedule permits uninterrupted operation every third calendar year. Beginning March 5, 1993, Wolf Creek was taken off-line for its sixth refueling and maintenance outage. The refueling outage took approximately 73 days to complete, during which time electric demand was met primarily by the Company's coal-fired generating units.

Nuclear. The owners of Wolf Creek have on hand or under contract 73 percent of the uranium required for operation of Wolf Creek through the year 2001. The balance is expected to be obtained through spot market and contract purchases.

Contractual arrangements are in place for 100 percent of Wolf Creek's uranium enrichment requirements for 1993-1996, 70 percent for 1997-1998 and 100 percent for 2003-2014. The balance of the 1997-2002 requirements is expected to be obtained through a combination of spot market and contract purchases. The decision not to contract for the full enrichment requirements is one of cost rather than availability of service.

Contractual arrangements are in place for the conversion of uranium to uranium hexafluoride sufficient to meet Wolf Creek's requirements through 1995 as well as the fabrication of fuel assemblies to meet Wolf Creek's requirements through 2012. During 1994, the Company plans to begin securing additional arrangements for uranium conversion for the post 1995 period.

The Nuclear Waste Policy Act of 1982 established schedules, guidelines and responsibilities for the Department of Energy (DOE) to develop and construct repositories for the ultimate disposal of spent fuel and high-level waste. The DOE has not yet constructed a high-level waste disposal site and has announced that a permanent storage facility may not be in operation prior to 2010 although an interim storage facility may be available earlier. Wolf Creek contains an on-site spent fuel storage facility which, under current regulatory guidelines, provides space for the storage of spent fuel through 2006 while still maintaining full core off-load capability. The Company believes adequate additional storage space can be obtained, as necessary.

Coal. The Company has a long-term coal supply contract with Amax Coal West, Inc. (AMAX) a subsidiary of Cyprus Amax Coal Company, to supply low sulfur coal to JEC from AMAX's Eagle Butte Mine or an alternate mine source of AMAX's Belle Ayr Mine, both located in the Powder River Basin in Cambell County, Wyoming. The contract expires December 31, 2020. The contract contains a schedule of minimum annual delivery quantities with deficient mmBTU provisions applicable to deficiencies in the scheduled delivery. The coal to be supplied is surface mined and has an average BTU content of approximately 8,300 BTU per pound and an average sulfur content of .43 lbs/mmBTU (see Environmental Matters). The average delivered cost of coal for JEC was approximately $1.045 per mmBTU or $17.35 per ton during 1993.

Coal is transported from Wyoming under a long-term rail transportation contract with Burlington Northern (BN) and Union Pacific (UP) to JEC through December 31, 2013. Rates are based on net load carrying capabilities of each rail car. The Company provides 770 aluminum rail cars, under a 20 year lease, to transport coal to JEC. During 1994, the Company will provide an additional 120 rail cars under a similar lease.

The two coal fired units at La Cygne generating station have an aggregate generating capacity of 677 MW (KG&E's 50 percent share) (see Item 2. Properties). The operator, Kansas City Power & Light Company (KCP&L), maintains coal contracts summarized in the following paragraphs.

During 1993, La Cygne 1 was converted to use low sulfur Powder River Basin coal which is supplied under the AMAX contract for La Cygne 2, discussed below. Illinois or Kansas/Missouri coal is blended with the Powder River Basin coal and is secured from time to time under spot market arrangements. La Cygne 1 uses a blend of 85 percent Powder River Basin coal. During the third and fourth quarters of 1993, the Company along with the operator secured supplemental Illinois or Kansas/Missouri coal, for blending purposes, on a short-term basis through spot market purchase orders.

La Cygne 2 and additional La Cygne 1 Powder River Basin coal was supplied, through a contract that expired December 31, 1993, by AMAX from its mines in Gillette, Wyoming. This low sulfur coal had an average BTU content of approximately 8,500 BTU per pound and a maximum sulfur content of .50 lbs/mmBTU (see Environmental Matters). For 1994, the operator has secured Powder River Basin coal, similar to the AMAX coal, from two sources; Carter Mining Company's Caballo Mine, a subsidiary of Exxon Coal USA; and Caballo Rojo Inc's Caballo Rojo Mine, a subsidiary of Drummond Inc. Transportation is covered by KCP&L through its Omnibus Rail Transportation Agreement with BN and Kansas City Southern Railroad through December 31, 1995. An alternative rail transportation agreement with Western Railroad Property, Inc. (WRPI), a partnership between UP and Chicago Northwestern (CNW), lasts through December 31, 1995. The WRPI/UP/CNW agreement is a supplemental access contract to handle tonnages not covered by the Omnibus contract.

During 1993, the average delivered cost of all coal procured for La Cygne 1 was approximately $0.81 per mmBTU or $14.24 per ton and the average delivered cost of Powder River Basin coal for La Cygne 2 was approximately $0.84 per mmBTU or $14.18 per ton.

The coal-fired units located at the Tecumseh and Lawrence Energy Centers have an aggregate generating capacity of 768 MW (see Item 2. Properties). The Company contracted with ARCH Mineral Corporation (ARCH Mineral) for low sulfur coal through December 31, 1993. The coal from ARCH Mineral was surface mined at its mine in Hanna, Wyoming and had an average BTU content of approximately 10,400 BTU per pound and an average sulfur content of .625 lbs/mmBTU (see Environmental Matters). During 1993, the average delivered cost of coal for the Lawrence units was approximately $1.254 per mmBTU or $29.13 per ton and the average delivered cost of coal for the Tecumseh units was approximately $1.229 per mmBTU or $26.19 per ton. The Company had a supplemental spot coal agreement, expiring December 31, 1993, with Cyprus Western Coal Company (Cyprus) to supply low-sulfur coal from Cyprus's Foidel Creek Mine located in Routt County, Colorado. The Company entered into a new five year coal supply agreement, effective January 1, 1994, with Cyprus for coal from the Foidel Creek mine. This coal will be transported under a new agreement with Southern Pacific Lines and Atchison and Topeka Santa Fe Railway Company. The coal supplied from Cyprus has an average BTU content of approximately 11,200 BTU per pound and an average sulfur content of .38 lbs/mmBTU. The Company anticipates that the Cyprus agreement will supply the minimum requirements of the Tecumseh and Lawrence Energy Centers and supplemental coal requirements will continue to be supplied from favorable coal markets in Wyoming, Utah, Colorado and/or New Mexico.

Natural Gas. The Company uses natural gas as a primary fuel in its Gordon Evans, Murray Gill, Abilene, and Hutchinson Energy Centers and in the gas turbine units at its Tecumseh generating station. Natural gas is also used as a supplemental fuel in the coal fired units at the Lawrence and Tecumseh generating stations. Natural gas for Gordon Evans and Murray Gill Energy Centers is supplied under a firm contract that runs through 1995 by Kansas Gas Supply (KGS). Short-term economical spot market purchases from the Williams Natural Gas (WNG) system provide the Company flexible natural gas to meet operational needs. Natural gas for the Company's Abilene and Hutchinson stations is supplied from the Company's main system (see Natural Gas Operations). Natural gas for the units at the Lawrence and Tecumseh stations is supplied through the WNG system under a short-term spot market agreement.

Oil. The Company uses oil as an alternate fuel when economical or when interruptions to gas make it necessary. Oil is also used as a supplemental fuel at each of the coal plants. All oil burned by the Company during the past several years has been obtained by spot market purchases. At December 31, 1993, the Company had approximately 4 million gallons of No. 2 and 14.7 million gallons of No. 6 oil which is sufficient to meet emergency requirements and protect against lack of availability of natural gas and/or the loss of a large generating unit.

Other Fuel Matters. The Company's contracts to supply fuel for its coal- and natural gas-fired generating units, with the exception of JEC, do not provide full fuel requirements at the various stations. Supplemental fuel is procured on the spot market to provide operational flexibility and, when the price is favorable, to take advantage of economic opportunities.

On March 26, 1992, in connection with the Merger, the Kansas Corporation Commission (KCC) approved the elimination of the Energy Cost Adjustment Clause (ECA) for most Kansas retail electric customers of both the Company and KG&E effective April 1, 1992. The provisions for fuel costs included in base rates were established at a level intended by the KCC to equal the projected average cost of fuel through August 1995 and to include recovery of costs provided by previously issued orders relating to coal contract settlements. Any increase or decrease in fuel costs from the projected average will be absorbed by the Company.

Set forth in the table below is information relating to the weighted average cost of fuel used by the Company.

KPL Plants	1993	1992	1991	1990	1989
Per Million BTU:					
Coal	$1.13	$1.30	$1.33	$1.33	$1.31
Gas	2.71	2.15	1.72	1.50	2.10
Oil	4.41	4.19	4.25	4.63	3.92
Cents per KWH Generation	1.31	1.49	1.52	1.53	1.51

KG&E Plants	1993	1992	1991	1990	1989
Per Million BTU:					
Nuclear	$0.35	$0.34	$0.32	$0.34	$0.34
Coal	0.96	1.25	1.32	1.32	1.38
Gas	2.37	1.95	1.74	1.96	1.91
Oil	3.15	4.28	4.13	3.01	3.30
Cents per KWH Generation	0.93	0.98	1.09	1.01	0.96

Environmental Matters. The Company currently holds all Federal and state environmental approvals required for the operation of all its generating units. The Company believes it is presently in substantial compliance with all air quality regulations (including those pertaining to particulate matter, sulfur dioxide and nitrogen oxides) promulgated by the State of Kansas and the Environmental Protection Agency (EPA).

The Federal sulfur dioxide standards, applicable to the Company's JEC and La Cygne 2 units, prohibit the emission of more than 1.2 pounds of sulfur dioxide per million BTU of heat input. Federal particulate matter emission standards applicable to these units prohibit: (1) the emission of more than 0.1 pounds of particulate matter per million BTU of heat input and (2) an opacity greater than 20 percent. Federal nitrogen oxides emission standards applicable to these units prohibit the emission of more than 0.7 pounds of nitrogen oxides per million BTU of heat input.

The JEC and La Cygne 2 units have met: (1) the sulfur dioxide standards through the use of low sulfur coal (See Coal); (2) the particulate matter standards through the use of electrostatic precipitators; and (3) the nitrogen oxide standards through boiler design and operating procedures. The JEC units are also equipped with flue gas scrubbers providing additional sulfur dioxide and particulate matter emission reduction capability.

The Kansas Department of Health and Environment regulations, applicable to the Company's other generating facilities, prohibit the emission of more than 2.5 pounds of sulfur dioxide per million BTU of heat input at the Company's Lawrence generating units and 3.0 pounds at all other generating units. The Company has contracted or intends to contract to purchase low sulfur coal (see Coal) which will allow compliance with such limits at Lawrence, Tecumseh and La Cygne 1. All facilities burning coal are equipped with flue gas scrubbers and/or electrostatic precipitators.

The Clean Air Act Amendments of 1990 (the Act) require a two-phase reduction in sulfur dioxide and nitrogen oxide emissions effective in 1995 and 2000 and a probable reduction in toxic emissions. To meet the monitoring and reporting requirements under the acid rain program, the Company is installing continuous monitoring and reporting equipment at a total cost of approximately $10 million. At December 31, 1993, the Company had completed approximately $4 million of these capital expenditures with the remaining $6 million of capital expenditures to be completed in 1994 and 1995. The Company does not expect additional equipment to reduce sulfur emissions to be necessary under Phase II. The Company currently has no Phase I affected units.

The nitrogen oxide and toxic limits, which were not set in the law, will be specified in future EPA regulations. The EPA has issued, for public comment, preliminary nitrogen oxide regulations for Phase I group 1 units. Nitrogen oxide regulations for Phase II units and Phase I group 2 units are mandated in the Act to be promulgated by January 1, 1997. Although the Company has no Phase I units, the final nitrogen oxide regulations for Phase 1 group 1 may allow for early compliance for Phase II group 1 units. Until such time as the Phase I group 1 nitrogen oxide regulations are final, the Company will be unable to determine its compliance options or related compliance costs.

All of the Company's generating facilities are in substantial compliance with the Best Practicable Technology and Best Available Technology regulations issued by EPA pursuant to the Clean Water Act of 1977. Most EPA regulations are administered in Kansas by the Kansas Department of Health and Environment.

Additional information with respect to Environmental Matters is discussed in Note 4 of the Notes to Consolidated Financial Statements included herein.

NATURAL GAS OPERATIONS

General. At December 31, 1993, the Company supplied natural gas at retail to approximately 1,093,000 customers in 519 communities and at wholesale to eight communities and two utilities in Kansas, Missouri and Oklahoma. The natural gas systems of the Company consisted of distribution systems in all three states purchasing natural gas from interstate pipeline companies and the main system, an integrated storage, gathering, transmission and distribution system. The Company also transports gas for its large commercial and industrial customers purchasing gas on the spot market. The Company earns approximately the same margin on volume of gas transported as on volumes sold except where limited discounting occurs in order to retain the customer's load.

As discussed previously, on January 31, 1994, the Company sold substantially all of its Missouri natural gas distribution properties and operations to Southern Union and sold the remaining Missouri properties to United Cities on February 28, 1994. Additional information with respect to the impact of the sale of the Missouri Properties is set forth in Notes 2 and 13 of the Notes to Consolidated Financial Statements.

The percentage of total natural gas deliveries, including transportation and operating revenues for 1993 by state were as follows:

	Total Natural Gas Deliveries	Total Natural Gas Operating Revenues
Kansas	54.6%	53.9%
Missouri	43.0%	43.5%
Oklahoma	2.4%	2.6%

The Company's natural gas deliveries for the last five years were as follows:

	1993	1992	1991	1990	1989
			(Thousands of MCF)		
Residential	110,045	93,779	97,297	95,247	104,057
Commercial	47,536	40,556	47,075	43,973	47,339
Industrial	1,490	2,214	2,655	3,207	5,637
Other	41	94	14,960*	1,361	1,403
Transportation	73,574	68,425	78,055	72,623	58,025
Total	232,686	205,068	240,042*	216,411	216,461

* Includes cumulative effect to January 1, 1991, of change in revenue recognition. The cumulative effect of this change increased natural gas sales by 14,838,000 MCF.

The Company's natural gas revenues for the last five years were as follows:

	1993	1992	1991	1990	1989
			(Thousands of Dollars)		
Residential	$529,260	$440,239	$433,871	$439,956	$430,250
Commercial	209,344	169,470	182,486	176,279	172,628
Industrial	7,294	7,804	10,546	12,994	18,021
Other	30,143	27,457	33,434	31,323	30,072
Transportation	28,781	28,393	30,002	25,496	24,309
Total	$804,822	$673,363	$690,339	$686,048	$675,280

In compliance with orders of the state commissions applicable to all natural gas utilities, the Company has established priority categories for service to its natural gas customers. The highest priority is for residential and small commercial customers and the lowest for large industrial customers. Natural gas delivered by the Company from its main system for use as fuel for electric generation is classified in the lowest priority category.

Interstate Pipeline Supply. During 1993, the Company purchased natural gas from interstate pipelines, producers, and marketers to distribute at retail to approximately 966,000 customers located in western Missouri, central and eastern Kansas and northeastern Oklahoma. The principal market area at December 31, 1993, was the seven county Kansas City metropolitan area (see page 3 regarding the sale of the Missouri Properties), which includes Kansas City and Independence in Missouri and Kansas City and the northeast Johnson County suburbs in Kansas. Other larger cities which were served in 1993 are St. Joseph and Joplin, Missouri; Wichita and Topeka, Kansas; and Bartlesville, Oklahoma.

During 1993, as a result of FERC Order No. 636, significant changes occurred regarding the acquisition of interstate pipeline supply and transportation services. The FERC has issued final decisions concerning the Company's major pipeline suppliers which authorized the implementation of restructured services before the 1993-94 winter heating season. Appeals have been filed in several of these cases concerning numerous issues addressed by the restructuring orders. The Company anticipates that implementation of restructured pipeline services will not significantly affect its ability to provide reliable service to its customers. For additional discussion, see Management's Discussion and Analysis included herein.

In 1993, the Company purchased approximately 56.9 billion cubic feet (BCF) or 38.7 percent of the interstate pipeline supply compared with 48.1 BCF or 39.4 percent for 1992, from Williams Natural Gas Company (WNG), a non-affiliated interstate pipeline transmission company. The Company had a contract with WNG for natural gas purchases which expired on September 30, 1993. The Company's purchase contract has been superseded by transportation agreements with WNG which have terms varying in length from one to twenty years. The Company now purchases all the natural gas it delivers to its customers direct from producers and marketers of natural gas. WNG transported 33.5 BCF under these agreements in 1993.

The Company has gas purchase contracts with Mobil Natural Gas, Inc., OXY USA, Inc., Williams Gas Marketing, Kansas Pipeline Company, L.P., Mesa, Tri-Power Fuels, Amoco, Mid-Kansas Partnership, and GPM Gas Corporation expiring at various times. Some of the Company's gas purchase contracts extend beyond the year 2000. The Company purchased approximately 77.8 BCF or 52.9 percent of its natural gas supply from these sources in 1993 and 63.9 BCF or 52.3 percent during 1992. Approximately 94.4 BCF of natural gas is made available annually under these contracts. The Company has limited rights to substitute spot gas for this gas under contract.

Other sources of supply for the Company's distribution systems were Panhandle Eastern Pipeline Company (Panhandle), Northern Natural Gas Company, Natural Gas Pipeline Company of America, intrastate pipelines, and spot market suppliers under short term contracts. These sources totalled 5.2 and 2.0 BCF for 1993 and 1992 representing 3.5 percent and 1.6 percent of the system requirements, respectively.

During 1993 and 1992, approximately 7.1 BCF and 8.2 BCF, respectively, were transferred from the Company's main system to serve a portion of Wichita, Kansas. These system transfers represent 4.9 percent and 6.7 percent, respectively, of the interstate system supply.

The average wholesale cost per thousand cubic feet (MCF) purchased for the distribution systems for the past five years was as follows:

Interstate Pipeline Supply
(Average Cost per MCF)

	1993	1992	1991	1990	1989
WNG	$3.57	$3.64	$3.61	$3.84	$3.23
Other	3.01	2.30	2.36	2.14	2.29
Total Average Cost	3.23	2.88	3.02	3.10	2.91

The increase in the total average cost per MCF in 1993 from 1992 reflects increased prices in the spot market.

Main System. The Company serves approximately 127,000 customers in central and north central Kansas with natural gas supplied through the main system. The principal market areas include Salina, Manhattan, Junction City, Great Bend, McPherson, Hutchinson and Wichita, Kansas.

Natural gas for the Company's main system is purchased from a combination of direct wellhead production, from the outlet of natural gas processing plants, and from interstate pipeline interconnects all within the State of Kansas. Such purchases are transported entirely through Company owned transmission lines in Kansas.

During 1993 the Company purchased from Mesa approximately 15.6 BCF of natural gas (including 2.5 BCF of make-up deliveries) pursuant to a contract expiring May 31, 1995 (the Hugoton Contract). This compares with 14.3 BCF (including 2.1 BCF of make-up deliveries) during 1992. These purchases represent approximately 53.7 percent and 55.2 percent, respectively, of the Company's main system requirements during such periods.

Pursuant to the Hugoton Contract, the Company expects to purchase approximately 16.8 BCF of natural gas constituting approximately 56.4 percent of the Company's main system requirements during 1994. Mesa dedicated its entire deliverability in the contract area to the Company. However, if the Company is unable to take 100% of such deliverability, such non-takes by the Company are released back to Mesa to sell to others. Under the terms of the Hugoton Contract, the Company is entitled to purchase annually the volume of natural gas the KCC allows to be produced from the Mesa wells, less gasoline plant shrinkage and the natural gas used by Mesa in its operations.

Spivey-Grabs field in south-central Kansas supplied approximately 4.8 and 5.4 BCF of natural gas in 1993 and 1992, constituting 16.6 percent and 20.9 percent, respectively, of the main system's requirements during such periods. Such natural gas is supplied pursuant to contracts with producers in the Spivey-Grabs field, most of which are for the life of the field, and under which the Company expects to receive approximately 5.2 BCF of natural gas in 1994.

Other sources of gas for the main system of 4.4 BCF or 15.2 percent of the system requirements were purchased from or transported through interstate pipelines during 1993. The remainder of the supply for the main system during 1993 and 1992 of 4.2 and 4.0 BCF representing 14.5 percent and 15.4 percent, respectively, was purchased directly from producers or gathering systems.

During 1993 and 1992, approximately 7.1 and 8.2 BCF, respectively, of the total main system supply was transferred to the Company's interstate system (see Interstate Pipeline Supply).

The main system's average wholesale cost per MCF purchased for the past five years was as follows:

Natural Gas Supply - Main System
(Average Cost per MCF)

	1993	1992	1991	1990	1989
Mesa-Hugoton Contract	$1.78(1)	$1.47(2)	$1.36(3)	$1.47(4)	$1.35
Other	2.69	2.66	2.68	2.54	2.63
Total Average Cost	2.20	2.00	1.94	1.98	1.84

(1) Includes 2.5 BCF @ $1.31/MCF of make-up deliveries.
(2) Includes 2.1 BCF @ $1.31/MCF of make-up deliveries.
(3) Includes 1.5 BCF @ $1.31/MCF of make-up deliveries.
(4) Includes 1.6 BCF @ $1.12/MCF and 1.8 BCF @ $1.31/MCF of make-up deliveries.

The Company has determined that it controlled an estimated 448 BCF of proved natural gas reserves as of December 31, 1993, for the main system. The Company made this determination based on a study and estimate prepared by K&A Energy Consultants, Inc., independent petroleum engineers and geologists, of the natural gas reserves under contract to the Company as of December 31, 1988, and changes in contracted reserves since the date of the study. The annual amount of natural gas available from these reserves is dependent upon production allowables granted by the KCC to wells in specific natural gas fields, and upon the deliverability of the wells under contract.

Production allowables for the Hugoton Field, set by the KCC, determine the amount of natural gas available to the Company. The production allowables granted by the KCC are reviewed in March and September of each year.

In the Company's opinion, its contracts and reserves are adequate to meet the present annual requirements of its main system high priority customers through 1994. The Company has contracted with various suppliers to assure adequate supplies will continue beyond 1994.

The load characteristics of the Company's natural gas customers creates relatively high volume demand on the main system during cold winter days. To assure peak day service to high priority customers, the Company has developed the Brehm natural gas storage facility near Pratt, Kansas with working storage capacity of 1.6 BCF. The Company has an agreement with Williams Natural Gas Company, expiring March 31, 1998, for an additional 3.3 BCF of storage in the Alden field in Kansas. Natural gas is transferred to and displaced from Alden through Williams's pipeline system.

Under the terms of a deferred delivery agreement between the Company and Enron Gas Marketing (EGM), the Company will receive approximately 1.5 BCF during the 1993-1994 heating season, which will complete the deferred delivery agreement.

The Company owns and operates the Brehm field, an underground natural gas storage facility in Pratt County, Kansas. This facility has a storage capacity of approximately 1.6 BCF.

The Company has developed additional storage for the main system in the Yaggy field near Hutchinson, Kansas. This field provides another 2 BCF of working storage capacity when fully operational, of which approximately 1 BCF was available for the heating season beginning November 1993.

Environmental Matters. For information with respect to Environmental Matters see Note 4 of Notes to Consolidated Financial Statements included herein.

SEGMENT INFORMATION

Financial information with respect to business segments as set forth in Note 13 of Notes to Consolidated Financial Statements included herein.

FINANCING

The Company's ability to issue additional debt and equity securities is restricted under limitations imposed by the charter and the Mortgage and Deed of Trust of Western Resources and KG&E.

Western Resources' mortgage prohibits additional first mortgage bonds from being issued (except in connection with certain refundings) unless the Company's net earnings available for interest, depreciation and property retirement for a period of 12 consecutive months within 15 months preceding the issuance are not less than the greater of twice the annual interest charges on, or 10% of the principal amount of, all first mortgage bonds outstanding after giving effect to the proposed issuance. Based on the Company's results for the 12 months ended December 31, 1993, approximately $457 million principal amount of additional first mortgage bonds could be issued (7.5 percent interest rate assumed).

Additional Western Resources bonds may be issued, subject to the restrictions in the preceding paragraph, on the basis of property additions not subject to an unfunded prior lien and on the basis of bonds which have been retired. As of December 31, 1993, the Company had approximately $148 million of net bondable property additions not subject to an unfunded prior lien entitling the Company to issue up to $89 million principal amount of additional bonds. As of December 31, 1993, the Company could also issue up to $203 million bonds on the basis of retired bonds.

With the sale of the Missouri Properties and the discharge of the Gas Service mortgage, the Company, as of January 31, 1994, had approximately $387 million of net bondable property additions not subject to an unfunded prior lien entitling the Company to issue up to $232 million of additional bonds. In addition, $203 million of retired bonds were repledged to the Trustee for the release of a portion of the gas properties sold. As of January 31, 1994, no additional bonds could be issued on the basis of retired bonds.

KG&E's mortgage prohibits additional first mortgage bonds from being issued (except in connection with certain refundings) unless KG&E's net earnings before income taxes and before provision for retirement and depreciation of property for a period of 12 consecutive months within 15 months preceding the issuance are not less than two and one-half times the annual interest charges on, or 10% of the principal amount of, all first mortgage bonds outstanding after giving effect to the proposed issuance. Based on KG&E's results for the 12 months ended December 31, 1993, approximately $1 billion principal amount of additional first mortgage bonds could be issued (7.5 percent interest rate assumed).

Additional KG&E bonds may be issued, subject to the restrictions in the preceding paragraph, on the basis of property additions not subject to an unfunded prior lien and on the basis of bonds which have been retired. As of December 31, 1993, KG&E had approximately $1.3 billion of net bondable property additions not subject to an unfunded prior lien entitling KG&E to issue up to $882 million principal amount of additional bonds. As of December 31, 1993, KG&E could also issue up to $115 million bonds on the basis of retired bonds.

The most restrictive provision of the Company's charter permits the issuance of additional shares of preferred stock without certain specified preferred stockholder approval only if, for a period of 12 consecutive months within 15 months preceding the issuance, net earnings available for payment of interest exceed one and one-half times the sum of annual interest requirements and dividend requirements on preferred stock after giving effect to the proposed issuance. After giving effect to the annual interest and dividend requirements on all debt and preferred stock outstanding at December 31, 1993, such ratio was 1.94 for the 12 months ended December 31, 1993.

REGULATION AND RATES

The Company is subject as an operating electric utility to the jurisdiction of the KCC and as a natural gas utility to the jurisdiction of the KCC, the Missouri Public Service Commission (MPSC), and the Corporation Commission of the State of Oklahoma (OCC), which have general regulatory authority over the Company's rates, extensions and abandonments of service and facilities, valuation of property, the classification of accounts and various other matters.

The Company is subject to the jurisdiction of the Federal Energy Regulatory Commission (FERC), KCC and MPSC with respect to the issuance of securities. There is no state regulatory body in Oklahoma having jurisdiction over the issuance of the Company's securities.

Additionally, the Company is subject to the jurisdiction of the FERC, including jurisdiction as to rates with respect to sales of electricity for resale. The Company is not engaged in the interstate transmission or sale of natural gas which would subject it to the regulatory provisions of the Natural Gas Act. KG&E is also subject to the jurisdiction of the Nuclear Regulatory Commission as to nuclear plant operations and safety.

Additional information with respect to Rate Matters and Regulation as set forth in Note 5 of Notes to Consolidated Financial Statements is included herein.

EMPLOYEE RELATIONS

As of December 31, 1993, the Company had 5,192 employees. The Company did not experience any strikes or work stoppages during 1993. The Company's current contracts with its two electric unions were negotiated in 1993 and expire June 30, 1995. The two contracts cover approximately 2,000 employees. The Company has contracts with 5 other unions representing approximately 1,450 employees. These contracts were negotiated in 1992 and will expire June 6, 1996. Following the 1994 sale of the Missouri Properties the Company had 4,164 employees.

EXECUTIVE OFFICERS OF THE COMPANY

Name	Age	Present Office	Other Offices or Positions Held During Past Five Years
John E. Hayes, Jr.	56	Chairman of the Board, President, and Chief Executive Officer (since October 1989)	Chairman of the Board (1989) Triad Capital Partners, St. Louis, Missouri President and Chief Executive Officer (1986 to 1989), Director (1984 to 1989), and Chairman of the Board (1986 to 1989), Southwestern Bell Telephone Company, St. Louis, Missouri Director (1986 to 1989) Southwestern Bell Corporation, St. Louis, Missouri
William E. Brown	54	President and Chief Executive Officer KPL (since October 1990)	President and Chief Operating Officer-KPL Division (1990) Executive Vice President and Chief Operating Officer (1987 to 1990) Acting President (1989)
James S. Haines, Jr.	47	Executive Vice President and Chief Administrative Officer (since March 1992)	Group Vice President (1985 to 1992) KG&E, Wichita, Kansas
Steven L. Kitchen	48	Executive Vice President and Chief Financial Officer (since March 1990)	Senior Vice President, Finance and Accounting (1987 to 1990)

John K. Rosenberg	48	Executive Vice President (since March 1990) and General Counsel (since May 1987)	Corporate Secretary (1988 to 1992) Vice President (1987 to 1990)
Carl M. Koupal, Jr.	40	Vice President, Corporate Communications, Marketing, and Economic Development (since September 1992)	Vice President, Marketing and Economic Development (1992) Director, Economic Development, (1985 to 1992) Jefferson City, Missouri
Rayford Price Price Winters	56	Vice President, Corporate Development (since September 1993)	President, (1990 to 1993) Rayford & Associates P.C., Austin, Texas Partner, (1988 to 1990) Thomas, & Newton, Austin, Texas
Kent R. Brown	48	President and Chief Executive Officer KG&E (since April 1992)	Group Vice President (1982 to 1992) KG&E, Wichita, Kansas
William L. Johnson(1)	51	President and Chief Executive Officer Gas Service (since October 1990)	President and Chief Operating Officer-Gas Service Division (1990) Vice President, District Operations (1985 to 1990) Michigan Consolidated Gas Company, Grand Rapids, Michigan
Jerry D. Courington	48	Controller (since February 1985)	

(1) Mr. Johnson left the Company on January 31, 1994.

The present term of office of each of the executive officers extends to May 3, 1994, or until their respective successors are chosen and appointed by the Board of Directors. There are no family relationships among any of the officers, nor any arrangements or understandings between any officer and other persons pursuant to which he/she was elected as an officer.

ITEM 2. PROPERTIES

The Company owns or leases and operates an electric generation, transmission, and distribution system in Kansas, a natural gas integrated storage, gathering, transmission and distribution system in Kansas, and a natural gas distribution system in Kansas, Missouri and Oklahoma (see page 3 with respect to the sale of the Missouri Properties).

During the five years ended December 31, 1993, the Company's gross property additions totalled $852,650,000 and retirements were $125,287,000.

ELECTRIC FACILITIES

Name	Unit No.	Year Installed	Principal Fuel	Unit Capacity (MW) (2)
Abilene Energy Center:				
Combustion Turbine	1	1973	Gas	67
Gordon Evans Energy Center:				
Steam Turbines	1	1961	Gas--Oil	150
	2	1967	Gas--Oil	367
Hutchinson Energy Center:				
Steam Turbines	1	1950	Gas	18
	2	1950	Gas	20
	3	1951	Gas	31
	4	1965	Gas	196
Combustion Turbines	1	1974	Gas	53
	2	1974	Gas	51
	3	1974	Gas	55
	4	1975	Oil	89
Jeffrey Energy Center (84%):				
Steam Turbines	1	1978	Coal	587
	2	1980	Coal	566
	3	1983	Coal	588
La Cygne Station (50%):				
Steam Turbines	1	1973	Coal	342
	2	1977	Coal	335
Lawrence Energy Center:				
Steam Turbines	2	1952	Gas	0 (1)
	3	1954	Coal	56
	4	1960	Coal	102
	5	1971	Coal	380
Murray Gill Energy Center:				
Steam Turbines	1	1952	Gas--Oil	46
	2	1954	Gas--Oil	69
	3	1956	Gas--Oil	107
	4	1959	Gas--Oil	105
Neosho Energy Center:				
Steam Turbines	3	1954	Gas--Oil	0 (1)

Name	Unit No.	Year Installed	Principal Fuel	Unit Capacity (MW) (2)
Tecumseh Energy Center:				
Steam Turbines	7	1957	Coal	83
	8	1962	Coal	147
Combustion Turbines	1	1972	Gas	19
	2	1972	Gas	19
Wichita Plant:				
Diesel Generator	5	1969	Diesel	3
Wolf Creek Generating Station (47%):				
Nuclear	1	1985	Uranium	533
Total				5,184

(1) These units have been "mothballed" for future use.

(2) Based on MOKAN rating.

The Company jointly-owns Jeffrey Energy Center (84%), La Cygne Station (50%) and Wolf Creek Generating Station (47%).

NATURAL GAS COMPRESSOR STATIONS AND STORAGE FACILITIES

The Company's transmission and storage facility compressor stations, all located in Kansas, as of December 31, 1993, are as follows:

Location	Driving Units	Year Installed	Type of Fuel	Mfr hp Ratings	Mfr Ratings of MCF/Hr Capacity at 14.65 Psia at 60 F
Abilene	4	1930	Gas	4,000	5,920
Bison	1	1951	Gas	440	316
Brehm Storage . .	2	1982	Gas	800	486
Calista	3	1987	Gas	4,400	7,490
Hope.	1	1970	Electric	600	44
Hutchinson. . . .	2	1989	Gas	1,600	707
Manhattan	1	1963	Electric	250	313
Marysville. . . .	1	1964	Electric	250	202
McPherson	1	1972	Electric	3,000	7,040
Minneola.	5	1952 - 1978	Gas	9,650	14,018
Pratt	3	1963 - 1983	Gas	1,700	3,145
Spivey.	4	1957 - 1964	Gas	7,200	1,368
Ulysses	12	1949 - 1981	Gas	26,630	15,244
Yaggy Storage . .	3	1993	Electric	7,500	5,000

The Company owns and operates an underground natural gas storage facility, the Brehm field in Pratt County, Kansas. This facility has a working storage capacity of approximately 1.6 BCF. The Company withdrew up to 16,930 MCF per day from this field to meet 1993 winter peaking requirements.

The Company owns and operates an underground natural gas storage field, the Yaggy field in Reno County, Kansas. This facility has a working storage capacity of approximately 0.8 BCF to be expanded to 2 BCF. The Company withdrew up to 6,280 MCF per day from this field to meet 1993 winter peaking requirements.

The Company has contracted with Williams Natural Gas Company for additional underground storage in the Alden field in Kansas. The contract, expiring March 31, 1998, enables the Company to supply customers with up to 75 million cubic feet per day of gas supply during winter peak periods. See Item I. Business, Gas Operations for proven recoverable gas reserve information.

ITEM 3. LEGAL PROCEEDINGS

Information on legal proceedings involving the Company is set forth in Note 15 of Notes to Consolidated Financial Statements included herein.

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

No matter was submitted during the fourth quarter of the fiscal year covered by this report to a vote of security holders, through the solicitation of proxies or otherwise.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY AND RELATED STOCKHOLDER MATTERS

Stock Trading. Western Resources common stock, which is traded under the ticker symbol WR, is listed on the New York Stock Exchange. As of March 14, 1994, there 45,317 common shareholders of record. For information regarding quarterly common stock price ranges for 1993 and 1992, see Note 16 of Notes to Consolidated Financial Statements included herein.

Dividend Policy. Western Resources common stock is entitled to dividends when and as declared by the Board of Directors. At December 31, 1993, the Company's retained earnings were restricted by $857,600 against the payment of dividends on common stock. However, prior to the payment of common dividends, dividends must be first paid to the holders of preferred stock and second to the holders of preference stock based on the fixed dividend rate for each series.

Dividends have been paid on the Company's common stock throughout the Company's history. Quarterly dividends on common stock normally are paid on or about the first of January, April, July, and October to shareholders of record as of about the third day of the preceding month. Future dividends depend upon future earnings, the financial condition of the Company and other factors. For information regarding quarterly dividend declarations for 1993 and 1992, see Note 16 of Notes to Consolidated Financial Statements included herein.

ITEM 6. SELECTED FINANCIAL DATA

Year Ended December 31,	1993	1992(1)	1991	1990	1989
			(Dollars in Thousands)		
Income Statement Data:					
Operating revenues:					
Electric	$1,104,537	$ 882,885	$ 471,839	$ 463,707	$ 452,343
Natural gas.	804,822	673,363	690,339	686,048	675,280
Total operating revenues . .	1,909,359	1,556,248	1,162,178	1,149,755	1,127,623
Operating expenses	1,617,296	1,317,079	1,032,557	1,017,765	1,002,087
Allowance for funds used during construction	2,631	2,002	1,070	1,181	1,503
Income before cumulative effect of accounting change	177,370	127,884	72,285	79,619	72,778
Cumulative effect to January 1, 1991, of change in revenue recognition.	-	-	17,360	-	-
Net income	177,370	127,884	89,645	79,619	72,778
Earnings applicable to common stock.	163,864	115,133	83,268	77,875	70,921

December 31,	1993	1992(1)	1991	1990	1989
			(Dollars in Thousands)		
Balance Sheet Data:					
Gross plant in service	$6,222,483	$6,033,023	$2,535,448	$2,421,562	$2,305,279
Construction work in progress. .	80,192	68,041	17,114	20,201	19,571
Total assets	5,412,048	5,438,906	2,112,513	2,016,029	1,959,044
Long-term debt and preference stock subject to mandatory redemption	1,673,988	2,077,459	690,612	595,524	552,538

Year Ended December 31,	1993	1992(1)	1991	1990	1989
Common Stock Data:					
Earnings per share before cumulative effect of accounting change.	$ 2.76	$ 2.20	$ 1.91	$ 2.25	$ 2.05
Cumulative effect to January 1, 1991, of change in revenue recognition per share.	-	-	.50	-	-
Earnings per share	$ 2.76	$ 2.20	$ 2.41	$ 2.25	$ 2.05
Dividends per share.	$ 1.94	$ 1.90	$ 2.04(2)	$ 1.80	$ 1.76
Book value per share	$23.08	$21.51	$18.59	$18.25	$17.80
Average shares outstanding(000's)	59,294	52,272	34,566	34,566	34,566
Interest coverage ratio (before income taxes, including AFUDC)	2.79	2.27	2.69	2.86	2.96

(1) Information reflects the merger with KG&E on March 31, 1992 (Note 3).

(2) Includes special, one-time dividend of $0.18 per share paid February 28, 1991.

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

FINANCIAL CONDITION

General: Earnings were $2.76 per share of common stock based on 59,294,091 average common shares for 1993, an increase from $2.20 in 1992 on 52,271,932 average common shares. The increase resulted from a return to near normal temperatures compared to unusually mild winter and summer temperatures in 1992, reduced interest costs, and the full twelve month effect of the merger with Kansas Gas and Electric Company (KG&E) on March 31, 1992 (the Merger).

Dividends per common share were $1.94 in 1993, an increase of four cents from 1992. In January 1994, the Board of Directors declared a quarterly dividend of 49 1/2 cents per common share, an increase of one cent over the previous quarter.

The book value per share was $23.08 at December 31, 1993, compared to $21.51 at December 31, 1992. The increase in book value is primarily the result of the issuance of additional common stock and an increase in retained earnings. The 1993 closing stock price of $34 7/8 was 151 percent of book value. There were 61,617,873 common shares outstanding at December 31, 1993.

On January 31, 1994, the Company sold substantially all of its Missouri natural gas distribution properties and operations to Southern Union Company (Southern Union). The Company sold the remaining Missouri properties to United Cities Gas Company (United Cities) on February 28, 1994. The properties sold to Southern Union and United Cities are referred to herein as the "Missouri Properties." With the sales the Company is no longer operating as a utility in the State of Missouri.

The portion of the Missouri Properties purchased by Southern Union was sold for an estimated sale price of $400 million, in cash, based on a calculation as of December 31, 1993. The final sale price will be calculated as of January 31, 1994, within 120 days of closing. Any difference between the estimated and final sale price will be adjusted through a payment to or from the Company.

United Cities purchased the Company's natural gas distribution system in and around the City of Palmyra, Missouri, for $665,000 in cash.

The operating revenues and operating income (unaudited) related to the Missouri Properties approximated $350 million and $21 million representing approximately 18 percent and seven percent, respectively, of the Company's total for 1993, and $299 million and $11 million representing approximately 19 percent and five percent, respectively, of the Company's total for 1992. Net utility plant (unaudited) for the Missouri Properties, at December 31, 1993, approximated $296 million and $272 million at December 31, 1992. This represents approximately seven percent at December 31, 1993, and six percent at December 31, 1992, of the total Company net utility plant. Separate audited financial information was not kept by the Company for the Missouri Properties. This unaudited financial information is based on assumptions and allocations of expenses of the Company as a whole.

Liquidity and Capital Resources: The Company's liquidity is a function of its ongoing construction program, designed to improve facilities which provide electric and natural gas service and meet future customer service requirements.

During 1993, construction expenditures for the Company's electric system were approximately $138 million and nuclear fuel expenditures were approximately $6 million. It is projected that adequate capacity margins will be maintained without the addition of any major generating facilities through the turn of the century. The construction expenditures for improvements on the natural gas system, including the Company's service line replacement program, were approximately $94 million during 1993, of which construction expenditures for the Missouri Properties were approximately $39 million.

Capital expenditures for 1994 to 1996 are anticipated to be as follows:

	Electric	Nuclear Fuel	Natural Gas
	(Dollars in Thousands)		
1994	$131,483	$ 20,995	$ 64,608
1995	143,391	21,469	69,482
1996	151,100	9,890	68,747

These expenditures are estimates prepared for planning purposes and are subject to revisions from time to time (see Note 4).

The Company's net cash flow to capital expenditures was 100 percent for 1993 and during the last five years has averaged 87 percent. The Company anticipates net cash flow to capital expenditures to be approximately 100 percent in 1994.

The Company's capital needs through 1998 are approximately $33.6 million for bond maturities and cash sinking fund requirements for bonds and preference stock. This capital as well as capital required for construction will be provided from internal and external sources available under then existing financial conditions.

The Company anticipates using the net proceeds from the sale of the Missouri Properties to reduce the Company's outstanding debt.

The embedded cost of long-term debt was 7.7% at December 31, 1993, a decrease from 7.9% at December 31, 1992. The decrease was primarily accomplished through refinancing of higher cost debt.

The Company's short-term financing requirements are satisfied, as needed, through the sale of commercial paper, short-term bank loans, and borrowings under other unsecured lines of credit maintained with banks. At December 31, 1993, short-term borrowings amounted to $441 million, of which $126 million was commercial paper (see Notes 8 and 9).

On September 20, 1993, KG&E terminated a long-term revolving credit agreement which provided for borrowings of up to $150 million. The loan agreement, which was effective through October 1994, was repaid without penalty.

At December 31, 1993, the Company had $200 million of First Mortgage Bonds available to be issued under a shelf registration filed August 24, 1993. Also at December 31, 1993, KG&E had $150 million of First Mortgage Bonds available to be issued under a shelf registration filed on August 24, 1993. On January 20, 1994, KG&E issued $100 million of First Mortgage Bonds, 6.20% Series due January 15, 2006, under the KG&E shelf registration. The net proceeds were used to reduce short-term debt.

On January 31, 1994, the Company redeemed the remaining $2,466,000 principal amount of Gas Service Company 8 1/2% Series First Mortgage Bonds due 1997.

KG&E has a long-term agreement that expires in 1995 which contains provisions for the sale of accounts receivable and unbilled revenues (receivables) and phase-in revenues up to a total of $180 million. Amounts related to receivables are accounted for as sales while those related to phase-in revenues are accounted for as collateralized borrowings. At December 31, 1993, KG&E had receivables amounting to $56.8 million which were considered sold.

The issuance and retirement of long-term debt, borrowings against the cash surrender value of corporate-owned life insurance policies (COLI), and the issuance of common stock during 1993 are summarized in the table below.

Long-term debt	Date	Issued	Retired
		(Dollars in Millions)	
7 3/8% due 2002 - KG&E	11/22/93		$ 25.0
8 3/8% due 2006 - KG&E			25.0
8 1/2% due 2007 - KG&E			25.0
9.35% due 1998	10/15/93		75.0
6 1/2% due 2005 - KG&E	08/12/93	$ 65.0	
8 1/8% due 2001 - KG&E	08/20/93		35.0
8 7/8% due 2008 - KG&E			30.0
7.65% due 2023	04/27/93	100.0	
8 3/4% due 2000	05/12/93		20.0
8 5/8% due 2005			35.0
8 3/4% due 2008			35.0
6% Pollution Control Revenue Refunding Bonds due 2033	02/09/93	58.5	
9 5/8% Pollution Control Refunding and Improvement Revenue Bonds due 2013			58.5
Bank term loan	01/26/93		230.0
Revolving credit agreements (net)	various		35.0
Other long-term debt and sinking funds	various	4.1	
COLI borrowings (net) (1)	various	183.3	
Common stock			
3,425,000 shares (2)	08/25/93	124.2	
147,323 shares (3)	various	5.3	

(1) The COLI borrowings will be repaid upon receipt of proceeds from death benefits under the contracts. See Note 1 of Notes to Consolidated Financial Statements for additional information on the accumulated cash surrender value of COLI policies.

(2) Issued in public offering for net proceeds of $121 million.

(3) Issued under the Dividend Reinvestment and Stock Purchase Plan (DRIP). The net proceeds from these issues of approximately $5.3 million were added to the general corporate funds of the Company. Shares issued under the DRIP may either be original issue shares or shares purchased on the open market.

The Company has a Customer Stock Purchase Plan (CSPP) under which retail electric and natural gas customers and employees of the Company may purchase common stock through monthly installments. The initial installment period runs from September 1993, through June 1994, with monthly installments plus accumulated interest converted to shares in August 1994. Shares issued under the CSPP may either be original issue shares or shares purchased on the open market. Approximately $14.7 million has been pledged for this installment period.

The capital structure at December 31, 1993, was 45 percent common stock equity, 6 percent preferred and preference stock, and 49 percent long-term debt. The capital structure at December 31, 1993, including short-term debt and current maturities of long-term debt and preference stock, was 40 percent common stock equity, 5 percent preferred and preference stock, and 55 percent debt.

RESULTS OF OPERATIONS

The following is an explanation of significant variations from prior year results in revenues, operating expenses, other income and deductions, interest charges and preferred and preference dividend requirements. The results of operations of the Company include the activities of KG&E since the Merger on March 31, 1992. Additional information relating to changes between years is provided in the Notes to Consolidated Financial Statements.

Revenues: The operating revenues of the Company are based on sales volumes and rates, authorized by certain state regulatory commissions and the FERC, charged for the sale and delivery of natural gas and electricity. Rates are designed to recover the cost of service and allow investors a fair rate of return. Future natural gas and electric sales will continue to be affected by weather conditions, competing fuel sources, customer conservation efforts, and the overall economy of the Company's service area.

The Kansas Corporation Commission (KCC) order approving the Merger provided a moratorium on increases, with certain exceptions, in the Company's jurisdictional electric and natural gas rates until August 1995. The KCC ordered refunds totalling $32 million to the combined companies' customers to share with customers the Merger-related cost savings achieved during the moratorium period. The first refund of $8.5 million was made in April 1992. A refund of the same amount was made in December 1993, and an additional refund of $15 million will be made in September 1994 (see Note 3).

On March 26, 1992, in connection with the Merger, the KCC approved the elimination of the Energy Cost Adjustment Clause for most Kansas retail electric customers of both the Company and KG&E effective April 1, 1992. The fuel costs are now included in base rates and were established at a level intended by the KCC to equal the projected average cost of fuel through August 1995. Any increase or decrease in fuel costs from the projected average will be absorbed by the Company.

Future natural gas revenues will be reduced as a result of the sale of the Missouri Properties by approximately $350 million annually based on Missouri revenues recorded in 1993 (see Note 2).

1993 COMPARED TO 1992: Electric revenues increased significantly in 1993 as a result of the Merger. Also contributing to the increase were increased electric sales for space heating, resulting from colder winter temperatures in the first quarter of 1993, and increased sales for cooling load, resulting from warmer temperatures in the second and third quarters of 1993. KG&E electric revenues of $617 million have been included in the Company's 1993 electric revenues. This compares to KG&E revenues of $424 million, from April 1, 1992, through December 31, 1992, included in the Company's 1992 electric revenues. Partially offsetting these increases in electric revenues was the amortization of the Merger-related customer refund.

Electric revenues for 1993 compared to pro forma revenues for 1992, giving effect to the Merger as if it had occurred at January 1, 1992, would have increased as a result of the warmer summer and colder winter temperatures in 1993. Retail sales of kilowatt hours on a pro forma comparative basis increased from approximately 14.6 billion for 1992 to approximately 15.5 billion for 1993, or six percent.

Natural gas revenues increased approximately 20 percent as a result of increased sales caused by colder winter temperatures, the full impact of increased retail natural gas rates (see Note 5), and an eleven percent increase in the unit cost of gas passed on to customers through the purchased gas adjustment clauses (PGA). The colder winter temperatures are reflected in a 17 percent increase in natural gas sales to residential customers.

1992 COMPARED TO 1991: Electric revenues increased significantly in 1992 as a result of the Merger. KG&E electric revenues for the nine months ended December 31, 1992, of $424 million have been included in the Company's electric revenues. Partially offsetting this increase in revenues were reduced retail electric sales as a result of the abnormally mild summer temperatures in 1992 and the amortization of the Merger-related customer refund.

Electric revenues for 1992 compared to pro forma revenues for 1991, giving effect to the Merger as if it had occurred at January 1, 1991, also would have been lower as a result of the mild summer and winter temperatures in 1992. Retail sales of kilowatthours on a pro forma comparative basis decreased from approximately 15.1 billion for 1991 to approximately 14.6 billion for 1992, or four percent.

Natural gas revenues decreased over two percent due to a nine percent decrease in natural gas deliveries, excluding sales related to the cumulative effect of the unbilled revenue adjustment in 1991. Also contributing to the decrease was an approximately four percent decrease in the unit cost of natural gas which is passed on to customers through the PGA. The decrease in sales can be attributed to mild winter temperatures in 1992. Partially offsetting the decreased sales were increased retail rates in Kansas and Missouri beginning early in 1992.

Operating Expenses: 1993 COMPARED TO 1992: Operating expenses increased for 1993 primarily as a result of the Merger. KG&E operating expenses of $470 million have been included in the Company's operating expenses for the year ended December 31, 1993. This compares to KG&E operating expenses of $316 million, from April 1, 1992, through December 31, 1992, included in the Company's 1992 operating expenses.

Other factors, excluding the Merger, contributing to the increase in operating expenses were higher fuel and purchased power expenses caused by increased electric sales to meet cooling load and increased natural gas purchases caused by a 16 percent increase in natural gas sales and an 11 percent higher unit cost of gas which is passed on to customers through the PGA.

Also contributing to the increase were higher general taxes due to increases in plant, the property tax assessment ratio, and higher mill levies. A constitutional amendment in Kansas changed the assessment on utility property from 30 to 33 percent. As a result of this change the Company had an increased property tax expense of approximately $6.1 million in 1993.

Partially offsetting the increases were savings as a result of the Merger and reduced net lease expense for La Cygne 2 (see Note 10).

At December 31, 1993, KG&E completed the accelerated amortization of deferred income tax reserves related to the allowance for borrowed funds used during construction capitalized for Wolf Creek Generating Station. The amortization of these deferred income tax reserves amounted to approximately $12 million in 1993. In accordance with the provisions of the Merger order (see Note 3), the Company is precluded from recovering the $12 million annual amortization in rates until the next rate filing. Therefore the Company's earnings will be impacted negatively until these income taxes are recovered in future rates.

1992 COMPARED TO 1991: Operating expenses increased significantly for 1992 as a result of the Merger. KG&E operating expenses for the nine months ended December 31, 1992, of $316 million have been included in the Company's operating expenses.

Other factors, excluding the Merger, contributing to increased operating expenses were a one-time charge for the Company's portion of the early retirement plan and voluntary separation program of approximately $11 million; higher depreciation and amortization expense caused by increased plant investment and the beginning of the amortization of previously deferred safety-related expenditures in Kansas; and increased property taxes due to increases in plant and tax mill levies.

Partially offsetting those increases in operating expenses was the commencement of savings as a result of the Merger. The Company also changed the depreciable life of Jeffrey Energy Center, for book purposes, to 40 years, resulting in a reduction to depreciation expense of approximately $5.4 million annually. Lower natural gas purchases as a result of the mild temperatures and a reduced unit cost also partially offset the increase in operating expenses.

As permitted under the La Cygne 2 generating station lease agreement, KG&E requested the Trustee Lessor to refinance $341,127,000 of secured facility bonds of the Trustee and owner of La Cygne 2. The transaction was requested to reduce the Company's recurring future net lease expense. To accomplish this transaction, a one-time payment of approximately $27 million was made which will be amortized over the remaining life of the lease and will be included in operating expense as part of the future lower lease expense. On September 29, 1992, the Trustee Lessor refinanced bonds with a coupon rate of approximately 11.7% with bonds having a coupon rate of approximately 7.7%.

Other Income and Deductions: Other income and deductions, net of taxes, increased $1.3 million in 1993 compared to 1992. KG&E other income and deductions, net of taxes, of $19 million have been included in the Company's total for 1993 compared to $17 million in 1992 from April 1, through December 31, 1992. Income from KG&E's COLI totalled $8 million in 1993.

Other income and deductions, net of taxes, was significantly higher in 1992 compared to 1991 as a result of the Merger. KG&E contributed, for the nine months ended December 31, 1992, $17 million to other income and deductions, net of taxes. Significant items of other income include approximately $9 million from KG&E's COLI and KG&E's recognition of the recovery of approximately $4.2 million of a previously written-off investment in commercial paper.

Interest Charges and Preferred and Preference Dividend Requirements: Interest charges for 1993 were higher as a result of the Merger. KG&E interest charges of $59 million for 1993 have been included in the Company's total interest charges compared to $53 million for the nine months ended December 31, 1992. The full twelve month effect of interest on debt to acquire KG&E also contributed to the increase in total interest charges. The increased interest charges have been partially offset through lower debt balances and reduced interest charges from refinancing higher cost long-term debt and lower interest rates on variable-rate debt. The Company's embedded cost of long-term debt decreased to 7.7% at December 31, 1993, compared to 7.9% and 8.6% at December 31, 1992 and 1991, respectively, primarily as a result of the refinancing of higher cost debt.

Total interest charges increased significantly for 1992 compared to 1991 as a result of the Merger. Partially offsetting this increase were lower short-term and long-term interest rates.

Preferred and preference dividend requirements increased six percent in 1993 and significantly in 1992 compared to 1991 as a result of the issuance of $50 million of 7.58% preference stock in the second quarter of 1992.

Merger Implementation: In accordance with the KCC Merger order, amortization of the acquisition adjustment will commence August 1995. The amortization will amount to approximately $19.6 million per year for 40 years. The Company can recover the amortization of the acquisition adjustment through cost savings under a sharing mechanism approved by the KCC as described in Note 3 of the Notes to the Consolidated Financial Statements. While the Company has achieved savings from the Merger, there is no assurance that the savings achieved will be sufficient to, or the cost savings sharing mechanism will operate as to fully offset the amortization of the acquisition adjustment.

In 1992 the Company completed the consolidation of certain operations of the Company and KG&E. In conjunction with these efforts the Company incurred costs of consolidating facilities, transferring certain employees, and other costs associated with completing the Merger. Certain of these costs related to KG&E have been considered in purchase accounting for the Merger. Other costs, including costs of the early retirement incentive programs and other employee severance compensation programs for former Kansas Power and Light Company employees were charged to expense in 1992. See Note 6 of Notes to Consolidated Financial Statements for a discussion regarding the early retirement and Merger severance plans.

OTHER INFORMATION

Inflation: Under the ratemaking procedures prescribed by the regulatory commissions to which the Company is subject, only the original cost of plant is recoverable in revenues as depreciation. Therefore, because of inflation, present and future depreciation provisions are inadequate for purposes of maintaining the purchasing power invested by common shareholders and the related cash flows are inadequate for replacing property. The impact of this ratemaking process on common shareholders is mitigated to the extent depreciable property is financed with debt that can be repaid with dollars of less purchasing power. While the Company has experienced relatively low inflation in the recent past, the cumulative effect of inflation on operating costs requires the Company to seek regulatory rate relief to recover these higher costs.

FERC Order No. 636: On April 8, 1992, the FERC issued Order No. 636 which the FERC intended to complete the deregulation of natural gas production and facilitate competition in the gas transportation industry. Order No. 636 is expected to affect the Company in several ways. The rules provide greater protection for pipeline companies by providing for recovery of all fixed costs through contracts with local distribution companies and other customers choosing to transport gas on a firm (non-interruptible) basis. The order also separates the purchase of natural gas from the transportation and storage of natural gas, shifting additional responsibility to distribution companies for the provision (through purchase and/or storage) of long-term gas supply and transportation to distribution points. Under the new rules, distribution companies elect the amount and type of services taken from pipelines. The Company may be liable to one or more of its pipeline suppliers for costs related to the transition from its traditional sales service to the restructured services required by Order No. 636. The Company believes substantially all of these costs will be recovered from its customers and any additional transition costs will be immaterial to the Company's financial position or results of operations.

The Company was an active participant in pipeline restructuring negotiations and does not anticipate any material difficulty in obtaining the pipeline services the Company needs to meet the requirements of its gas operations.

Environmental: The Company has recognized the importance of environmental responsibility and has taken a proactive position with respect to the potential environmental liability associated with former manufactured gas sites. The Company has an agreement with the Kansas Department of Health and Environment to systematically evaluate these sites in Kansas (see Note 4).

The Company currently has no Phase I affected units under the Clean Air Act of 1990. Until such time that additional regulations become final the Company will be unable to determine its compliance options or related compliance costs (see Note 4).

Energy Policy Act: The 1992 Energy Policy Act (Act) requires increased efficiency of energy usage and will potentially change the way electricity is marketed. The Act also provides for increased competition in the wholesale electric market by permitting the FERC to order third party access to utilities' transmission systems and by liberalizing the rules for ownership of generating facilities. As part of the Merger, the Company agreed to open access to its transmission system. Another part of the Act requires a special assessment to be collected from utilities for a uranium enrichment, decontamination, and decommissioning fund. KG&E's portion of the assessment for Wolf Creek is approximately $7 million, payable over 15 years. Management expects such costs to be recovered through the ratemaking process.

Statement of Financial Accounting Standards No. 106 (SFAS 106) and No. 112 (SFAS 112): For discussion regarding the effect of SFAS 106 and SFAS 112 on the Company see Note 6 of Notes to the Consolidated Financial Statements.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

TABLE OF CONTENTS

SCHEDULES OMITTED

The following schedules are omitted because of the absence of the conditions under which they are required or the information is included in the financial statements and schedules presented: I, II, III, IV, VII, VIII, IX, X, XI, XII and XIII.

REPORT OF INDEPENDENT PUBLIC ACCOUNTANTS

To the Shareholders and Board of Directors of Western Resources, Inc.:

We have audited the accompanying consolidated balance sheets and statements of capitalization of Western Resources, Inc., and subsidiaries as of December 31, 1993 and 1992, and the related consolidated statements of income, cash flows, taxes and common stock equity for each of the three years in the period ended December 31, 1993. 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 did not audit the financial statements of Kansas Gas and Electric Company, a wholly-owned subsidiary of Western Resources, Inc., as of and for the year ended December 31, 1992, which statements reflect assets and revenues of 61 percent and 27 percent, respectively, of the consolidated totals for 1992. Those statements were audited by other auditors whose report has been furnished to us and our opinion, insofar as it relates to the amounts included for that entity, is based solely on the report of other auditors.

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 and the report of other auditors provide a reasonable basis for our opinion.

In our opinion, based on our audit and the report of other auditors, the financial statements referred to above present fairly, in all material respects, the financial position of Western Resources, Inc., and subsidiaries as of December 31, 1993 and 1992, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 1993, in conformity with generally accepted accounting principles.

As explained in Note 1 to the consolidated financial statements, effective January 1, 1991, the Company changed to a preferred method of accounting for revenue recognition. As explained in Note 12 to the consolidated financial statements, effective January 1, 1992, the Company changed its method of accounting for income taxes. As explained in Note 6 to the consolidated financial statements, effective January 1, 1993, the Company changed its method of accounting for postretirement benefits.

Our audit was made for the purpose of forming an opinion on the basic financial statements taken as a whole. The financial statement schedules listed in the table of contents on page 32 are the responsibility of the Company's management and are presented for purposes of complying with the Securities and Exchange Commission's rules and are not a part of the basic financial statements. These schedules have been subjected to the auditing procedures applied in the audit of the basic financial statements and, in our opinion and the opinion of other auditors, fairly state in all material respects the financial data required to be set forth therein in relation to the basic financial statements taken as a whole.

Kansas City, Missouri,
January 28, 1994

ARTHUR ANDERSEN & CO.

WESTERN RESOURCES, INC.
CONSOLIDATED BALANCE SHEETS

	December 31, 1993	December 31, 1992
	(Dollars in Thousands)	
ASSETS		
UTILITY PLANT (Notes 1 and 11):		
Electric plant in service	$5,110,617	$5,008,654
Natural gas plant in service	1,111,866	1,024,369
	6,222,483	6,033,023
Less - Accumulated depreciation	1,821,710	1,691,623
	4,400,773	4,341,400
Construction work in progress	80,192	68,041
Nuclear fuel (net)	29,271	33,312
Net utility plant	4,510,236	4,442,753
OTHER PROPERTY AND INVESTMENTS:		
Net non-utility investments	61,497	47,680
Decommissioning trust (Note 4)	13,204	9,272
Other	10,658	13,855
	85,359	70,807
CURRENT ASSETS:		
Cash and cash equivalents (Note 1)	1,217	875
Accounts receivable and unbilled revenues (net) (Note 1)	238,137	222,601
Fossil fuel, at average cost	30,934	49,007
Gas stored underground, at average cost	51,788	14,644
Materials and supplies, at average cost	55,156	59,357
Prepayments and other current assets	34,128	17,574
	411,360	364,058
DEFERRED CHARGES AND OTHER ASSETS:		
Deferred future income taxes (Note 12)	135,991	150,636
Deferred coal contract settlement costs (Note 5)	21,247	24,520
Phase-in revenues (Note 5)	78,950	96,495
Corporate-owned life insurance (net) (Note 1)	4,743	146,713
Other deferred plant costs	32,008	32,212
Other (Note 5)	132,154	110,712
	405,093	561,288
TOTAL ASSETS	$5,412,048	$5,438,906
CAPITALIZATION AND LIABILITIES		
CAPITALIZATION (see statement)	$3,121,021	$3,350,684
CURRENT LIABILITIES:		
Short-term debt (Note 9)	440,895	222,225
Long-term debt due within one year (Note 8)	3,204	1,961
Preference stock redeemable within one year (Note 14)	-	1,300
Accounts payable	172,338	215,507
Accrued taxes	46,076	38,591
Accrued interest and dividends	65,825	71,877
Other	65,492	48,045
	793,830	599,506
DEFERRED CREDITS AND OTHER LIABILITIES:		
Deferred income taxes (Note 12)	968,637	990,155
Deferred investment tax credits (Note 12)	150,289	149,946
Deferred gain from sale-leaseback (Note 10)	261,981	271,621
Other	116,290	76,994
	1,497,197	1,488,716
COMMITMENTS AND CONTINGENCIES (Notes 4 and 15)		
TOTAL CAPITALIZATION AND LIABILITIES	$5,412,048	$5,438,906

The Notes to Consolidated Financial Statements are an integral part of this statement.

WESTERN RESOURCES, INC.
CONSOLIDATED STATEMENTS OF INCOME

	1993	1992(1)	1991
	Year Ended December 31, (Dollars in Thousands, except Per Share Amounts)		
OPERATING REVENUES (Notes 1 and 5):			
Electric	$1,104,537	$ 882,885	$ 471,839
Natural gas	804,822	673,363	690,339
Total operating revenues	1,909,359	1,556,248	1,162,178
OPERATING EXPENSES:			
Fuel used for generation:			
Fossil fuel	237,053	190,653	146,256
Nuclear fuel	13,275	10,126	-
Power purchased	16,396	14,819	5,335
Natural gas purchases	500,189	403,326	439,323
Other operations	349,160	296,642	193,319
Maintenance	117,843	101,611	60,515
Depreciation and amortization	164,364	144,013	85,735
Amortization of phase-in revenues	17,545	13,158	-
Taxes (see statement):			
Federal income	62,420	34,905	24,516
State income	15,558	7,095	6,066
General	123,493	100,731	71,492
Total operating expenses	1,617,296	1,317,079	1,032,557
OPERATING INCOME	292,063	239,169	129,621
OTHER INCOME AND DEDUCTIONS (net of taxes)	25,482	24,186	3,351
INCOME BEFORE INTEREST CHARGES	317,545	263,355	132,972
INTEREST CHARGES:			
Long-term debt	123,551	117,464	51,267
Other	19,255	20,009	10,490
Allowance for borrowed funds used during construction (credit)	(2,631)	(2,002)	(1,070)
Total interest charges	140,175	135,471	60,687
INCOME BEFORE CUMULATIVE EFFECT OF ACCOUNTING CHANGE	177,370	127,884	72,285
Cumulative Effect to January 1, 1991, of Change in Revenue Recognition (net of taxes) (Note 1)	-	-	17,360
NET INCOME	177,370	127,884	89,645
PREFERRED AND PREFERENCE DIVIDENDS	13,506	12,751	6,377
EARNINGS APPLICABLE TO COMMON STOCK	$ 163,864	$ 115,133	$ 83,268
AVERAGE COMMON SHARES OUTSTANDING	59,294,091	52,271,932	34,566,170
EARNINGS PER AVERAGE COMMON SHARE OUTSTANDING BEFORE CUMULATIVE EFFECT OF ACCOUNTING CHANGE	$ 2.76	$ 2.20	$ 1.91
Cumulative Effect to January 1, 1991, of Change in Revenue Recognition Per Share	-	-	.50
EARNINGS PER AVERAGE COMMON SHARE OUTSTANDING	$ 2.76	$ 2.20	$ 2.41
DIVIDENDS DECLARED PER COMMON SHARE	$ 1.94	$ 1.90	$ 2.04(2)

(1) Information reflects the merger with KG&E on March 31, 1992 (Note 3).
(2) Includes special, one-time dividend of $0.18 per share paid February 28, 1991.

The Notes to Consolidated Financial Statements are an integral part of this statement.

WESTERN RESOURCES, INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	1993	1992(1)	1991
	(Dollars in Thousands)		
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income	$ 177,370	$ 127,884	$ 89,645
Depreciation and amortization	164,364	144,013	85,735
Other amortization (including nuclear fuel)	11,254	8,930	-
Deferred taxes and investment tax credits (net)	27,686	26,900	9,319
Amortization of phase-in revenues	17,545	13,158	-
Corporate-owned life insurance	(21,650)	(14,704)	-
Amortization of gain from sale-leaseback	(9,640)	(7,231)	-
Changes in other working capital items:			
Accounts receivable and unbilled revenues (net)(Note 1)	(15,536)	(12,227)	(72,879)
Fossil fuel	18,073	14,990	(522)
Gas stored underground	(37,144)	4,522	(2,340)
Accounts payable	(43,169)	(10,194)	(3,125)
Accrued taxes	7,485	(52,185)	(14,130)
Other	(3,165)	(19,433)	11,661
Changes in other assets and liabilities	(18,569)	21,508	31,992
Net cash flows from operating activities	274,904	245,931	135,356
CASH FLOWS USED IN INVESTING ACTIVITIES:			
Additions to utility plant	237,631	202,493	125,675
Merger with KG&E	-	473,752	-
Utility investment	2,500	-	-
Non-utility investments (net)	14,271	29,099	18,125
Corporate-owned life insurance policies	27,268	20,233	-
Death proceeds of corporate-owned life insurance policies	(10,160)	(6,789)	-
Cash flows used in investing activities	271,510	718,788	143,800
CASH FLOWS FROM FINANCING ACTIVITIES:			
Short-term debt (net)	218,670	42,825	20,300
Bank term loan issued for Merger with KG&E	-	480,000	-
Bank term loan retired	(230,000)	(250,000)	-
Bonds issued	223,500	485,000	-
Bonds retired	(366,466)	(236,966)	(30,233)
Revolving credit agreements (net)	(35,000)	-	-
Other long-term debt (net)	7,043	14,498	-
Common stock issued (net)	125,991	-	-
Preference stock issued (net)	-	50,000	98,870
Preference stock redeemed	(2,734)	(2,600)	(1,300)
Bank term loan issuance expenses	-	(10,753)	-
Borrowings against life insurance policies (net)	183,260	(5,649)	-
Dividends on preferred, preference and common stock	(127,316)	(99,440)	(76,891)
Net cash flows from (used in) financing activities	(3,052)	466,915	10,746
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	342	(5,942)	2,302
CASH AND CASH EQUIVALENTS:			
BEGINNING OF THE PERIOD	875	6,817	4,515
END OF THE PERIOD	$ 1,217	$ 875	$ 6,817
SUPPLEMENTAL DISCLOSURES OF CASH FLOW INFORMATION			
CASH PAID FOR:			
Interest on financing activities (net of amount capitalized)	$ 171,734	$ 128,505	$ 58,462
Income taxes	49,108	24,966	40,062
COMPONENTS OF MERGER WITH KG&E:			
Assets acquired		$3,142,455	
Liabilities assumed		(2,076,821)	
Common stock issued		(589,920)	
Cash paid		475,714	
Less cash acquired		(1,962)	
Net cash paid		$ 473,752	

(1) Information reflects the merger with KG&E on March 31, 1992 (Note 3).
The Notes to Consolidated Financial Statements are an integral part of this statement.

WESTERN RESOURCES, INC.
CONSOLIDATED STATEMENTS OF TAXES

	Year Ended December 31, 1993	1992(1)	1991
	(Dollars in Thousands)		
FEDERAL INCOME TAXES:			
Payable currently	$ 41,200	$ 16,687	$ 18,479
Deferred taxes arising from:			
Depreciation and other property related items	25,552	25,163	9,662
Energy and purchased gas adjustment clauses	(8,192)	(4,180)	(15,535)
Unbilled revenues	-	2,458	17,249
Natural gas line survey and replacement program	355	(1,106)	1,015
Other	6,166	4,121	(1,109)
Amortization of investment tax credits	(1,982)	(4,918)	(4,238)
Total Federal income taxes	63,099	38,225	25,523
Federal income taxes applicable to non-operating items	(679)	(3,320)	(1,007)
Total Federal income taxes charged to operations	62,420	34,905	24,516
STATE INCOME TAXES:			
Payable currently	9,869	2,522	4,033
Deferred (net)	5,787	5,352	2,276
Total state income taxes	15,656	7,874	6,309
State income taxes applicable to non-operating items	(98)	(779)	(243)
Total state income taxes charged to operations	15,558	7,095	6,066
GENERAL TAXES:			
Property and other taxes	84,583	68,643	40,429
Franchise taxes	22,878	19,583	20,576
Payroll taxes	16,032	12,505	10,566
Total general taxes	123,493	100,731	71,571
General taxes applicable to non-operating items	-	-	(79)
Total general taxes charged to operations	123,493	100,731	71,492
TOTAL TAXES CHARGED TO OPERATIONS	$201,471	$142,731	$102,074

The effective income tax rates set forth below are computed by dividing total Federal and state income taxes by the sum of such taxes and net income. The difference between the effective rates and the Federal statutory income tax rates are as follows:

Year Ended December 31,	1993	1992	1991
EFFECTIVE INCOME TAX RATE	31.0%	27.0%	32.2%
EFFECT OF:			
Additional depreciation	(2.9)	(5.1)	(2.7)
Accelerated amortization of certain deferred taxes	6.0	7.6	3.9
State income taxes	(4.0)	(2.6)	(4.0)
Amortization of investment tax credits	2.7	3.4	3.2
Corporate-owned life insurance	3.0	2.9	-
Other differences	(.8)	.8	1.4
STATUTORY FEDERAL INCOME TAX RATE	35.0%	34.0%	34.0%

(1) Information reflects the merger with KG&E on March 31, 1992 (Note 3).

The Notes to Consolidated Financial Statements are an integral part of this statement.

WESTERN RESOURCES, INC.
CONSOLIDATED STATEMENTS OF CAPITALIZATION

	December 31, 1993		1992	
	(Dollars in Thousands)			
COMMON STOCK EQUITY (see statement):				
Common stock, par value $5 per share, authorized 85,000,000 shares, outstanding 61,617,873 and 58,045,550 shares, respectively . .	$ 308,089		$ 290,228	
Paid-in capital.	667,738		559,636	
Retained earnings.	446,348		398,503	
	1,422,175	45%	1,248,367	37%
CUMULATIVE PREFERRED AND PREFERENCE STOCK (Note 14):				
Not subject to mandatory redemption,				
Par value $100 per share, authorized 600,000 shares, outstanding -				
4 1/2% Series, 138,576 shares	13,858		13,858	
4 1/4% Series, 60,000 shares.	6,000		6,000	
5% Series, 50,000 shares.	5,000		5,000	
	24,858		24,858	
Subject to mandatory redemption,				
Without par value, $100 stated value, authorized 4,000,000 shares, outstanding -				
8.70% Series, 0 and 157,000 shares.	-		15,700	
7.58% Series, 500,000 shares.	50,000		50,000	
8.50% Series, 1,000,000 shares.	100,000		100,000	
Less: Preference stock reacquired, 135,000 shares	-		12,967	
Preference stock redeemable within one year.	-		1,300	
	150,000		151,433	
	174,858	6%	176,291	5%
LONG-TERM DEBT (Note 8)				
First mortgage bonds	842,466		984,932	
Pollution control bonds.	508,440		508,940	
Other pollution control obligations.	13,980		14,205	
Bank term loan	-		230,000	
Revolving credit agreements.	115,000		150,000	
Other long-term agreement.	53,913		46,640	
Less:				
Unamortized premium and discount (net)	6,607		6,730	
Long-term debt due within one year	3,204		1,961	
	1,523,988	49%	1,926,026	58%
TOTAL CAPITALIZATION	$3,121,021	100%	$3,350,684	100%

The Notes to Consolidated Financial Statements are an integral part of this statement.

WESTERN RESOURCES, INC.
CONSOLIDATED STATEMENTS OF COMMON STOCK EQUITY

	Common Stock	Paid-in Capital	Retained Earnings
	(Dollars in Thousands)		
BALANCE DECEMBER 31, 1990, 34,566,170 shares.	$172,831	$ 88,222	$369,772
Net income.			89,645
Cash dividends:			
Preferred and preference stock.			(6,377)
Common stock, $2.04(1) per share.			(70,514)
Expenses on preference stock.		(1,123)	(7)
BALANCE DECEMBER 31, 1991, 34,566,170 shares.	172,831	87,099	382,519
Net income.			127,884
Cash dividends:			
Preferred and preference stock.			(12,751)
Common stock, $1.90 per share			(99,135)
Expenses on preference stock.		14	(14)
Issuance of 23,479,380 shares of common stock in the merger with KG&E	117,397	472,523	
BALANCE DECEMBER 31, 1992, 58,045,550 shares.	290,228	559,636	398,503
Net income.			177,370
Cash dividends:			
Preferred and preference stock.			(13,506)
Common stock, $1.94 per share			(116,019)
Expenses on common and preference stock		(3,453)	
Issuance of 3,572,323 shares of common stock.	17,861	111,555	
BALANCE DECEMBER 31, 1993, 61,617,873 shares.	$308,089	$667,738	$446,348

(1) Includes special, one-time dividend of $0.18 per share paid February 28, 1991.

The Notes to Consolidated Financial Statements are an integral part of this statement.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

General: The consolidated financial statements of Western Resources, Inc. (the Company, Western Resources), include the accounts of its wholly-owned subsidiaries, Astra Resources, Inc., Kansas Gas and Electric Company (KG&E) since March 31, 1992 (see Note 3), and KPL Funding Corporation (KFC). KG&E owns 47 percent of Wolf Creek Nuclear Operating Corporation (WCNOC), the operating company for Wolf Creek Generating Station (Wolf Creek). The Company records its proportionate share of all transactions of WCNOC as it does other jointly-owned facilities. All significant intercompany transactions have been eliminated. The operations of Astra Resources, Inc., and KFC are not material to the Company's results of operations. The accounting policies of the Company are in accordance with generally accepted accounting principles as applied to regulated public utilities. The accounting and rates of the Company are subject to requirements of certain state regulatory commissions and the Federal Energy Regulatory Commission (FERC). The Company is doing business as KPL, Gas Service, and, through its wholly-owned subsidiary, KG&E.

Utility Plant: Utility plant is stated at cost. For constructed plant, cost includes contracted services, direct labor and materials, indirect charges for engineering, supervision, general and administrative costs, and an allowance for funds used during construction (AFUDC). The AFUDC rate was 4.10% in 1993, 5.99% in 1992, and 6.25% in 1991. The cost of additions to utility plant and replacement units of property is capitalized. Maintenance costs and replacement of minor items of property are charged to expense as incurred. When units of depreciable property are retired, they are removed from the plant accounts and the original cost plus removal charges less salvage are charged to accumulated depreciation.

Depreciation: Depreciation is provided on the straight-line method based on estimated useful lives of property. Composite provisions for book depreciation approximated 3.02% during 1993, 3.03% during 1992, and 3.34% during 1991 of the average original cost of depreciable property.

Cash and Cash Equivalents: For purposes of the Consolidated Statements of Cash Flows, cash and cash equivalents include cash on hand and highly liquid collateralized debt instruments purchased with maturities of three months or less.

Income Taxes: Income tax expense includes provisions for income taxes currently payable and deferred income taxes calculated in conformance with income tax laws, regulatory orders, and Statement of Financial Accounting Standards No. 109 (SFAS 109) (see Note 12).

Investment tax credits are deferred as realized and amortized to income over the life of the property which gave rise to the credits.

Revenues: Effective January 1, 1991, the Company changed its method of accounting for recognizing electric and natural gas revenues to provide for the accrual of estimated unbilled revenues. The accounting change provides a better matching of revenues with costs of services provided to customers and also serves to conform the Company's accounting treatment of unbilled revenues with the tax treatment of such revenues. Unbilled revenues represent the estimated amount customers will be billed for service provided from the time meters were last read to the end of the accounting period. Meters are read and services are billed on a cycle basis and, prior to the accounting change, revenues were recognized in the accounting period during which services were billed.

The after-tax effect of the change in accounting method for the year ended December 31, 1991, was an increase in net income of $15.9 million or $0.46 per share. This increase was a combination of an increase of $17.3 million or $0.50 per share, attributable to the cumulative effect of the accounting change prior to January 1, 1991, and a decrease of $1.4 million or $0.04 per share in the 1991 income before cumulative effect of a change in accounting principle. Unbilled revenues of $99 and $86 million are recorded as a component of accounts receivable on the consolidated balance sheets as of December 31, 1993 and 1992, respectively. Certain amounts of unbilled revenues have been sold (see Note 8).

The Company had reserves for doubtful accounts receivable of $4.3 and $3.3 million at December 31, 1993 and 1992, respectively.

Fuel Costs: The cost of nuclear fuel in process of refinement,conversion, enrichment, and fabrication is recorded as an asset at original cost and is amortized to expense based upon the quantity of heat produced for the generation of electricity. The accumulated amortization of nuclear fuel in the reactor at December 31, 1993 and 1992, was $17.4 million and $26.0 million, respectively.

Cash Surrender Value of Life Insurance Contracts: The following amounts related to corporate-owned life insurance contracts (COLI), primarily with one highly rated major insurance company, are recorded on the consolidated balance sheets (millions of dollars):

	1993	1992
Cash surrender value of contracts. . .	$ 326.3	$ 256.3
Prepaid COLI	11.9	7.0
Borrowings against contracts	(321.5)	(109.6)
COLI (net).	$ 16.7	$ 153.7

The decrease in COLI (net) is a result of increased borrowings against the accumulated cash surrender value of the COLI policies. The COLI borrowings will be repaid with proceeds from death benefits. Management expects to realize increases in the cash surrender value of contracts resulting from premiums and investment earnings on a tax free basis upon receipt of proceeds from death benefits under the contracts. Interest expense included in other income and deductions, net of taxes, related to KG&E's COLI for 1993 and the nine months ended December 31, 1992, was $11.9 and $5.3 million, respectively.

As approved by the Kansas Corporation Commission (KCC) and Missouri Public Service Commission (MPSC), the Company is using a portion of the net income stream generated by COLI policies purchased in 1993 and 1992 by the Company (see Note 6) to offset Statement of Financial Accounting Standards No. 106 (SFAS 106) expenses.

Reclassifications: Certain amounts in prior years have been reclassified to conform with classifications used in the current year presentation.

2. SALE OF MISSOURI NATURAL GAS DISTRIBUTION PROPERTIES

On January 31, 1994, the Company sold substantially all of its Missouri natural gas distribution properties and operations to Southern Union Company (Southern Union). The Company sold the remaining Missouri properties to United Cities Gas Company (United Cities) on February 28, 1994. The properties sold to Southern Union and United Cities are referred to herein as the "Missouri Properties." With the sales the Company is no longer operating as a utility in the State of Missouri.

The portion of the Missouri Properties purchased by Southern Union was sold for an estimated sale price of $400 million, in cash, based on a calculation as of December 31, 1993. The final sale price will be calculated as of January 31, 1994, within 120 days of closing. Any difference between the estimated and final sale price will be adjusted through a payment to or from the Company.

United Cities purchased the Company's natural gas distribution system in and around the City of Palmyra, Missouri, for $665,000 in cash.

The operating revenues and operating income (unaudited) related to the Missouri Properties approximated $350 million and $21 million representing approximately 18 percent and seven percent, respectively, of the Company's total for 1993, and $299 million and$11 million representing approximately 19 percent and five percent, respectively, of the Company's total for 1992. Net utility plant (unaudited) for the Missouri Properties, at December 31, 1993, approximated $296 million and $272 million at December 31, 1992. This represents approximately seven percent at December 31, 1993, and six percent at December 31, 1992, of the total Company net utility plant. Separate audited financial information was not kept by the Company for the Missouri Properties. This unaudited financial information is based on assumptions and allocations of expenses of the Company as a whole.

3. ACQUISITION AND MERGER

On March 31, 1992, the Company, through its wholly-owned subsidiary KCA Corporation (KCA), acquired all of the outstanding common and preferred stock of Kansas Gas and Electric Company for $454 million in cash and 23,479,380 shares of common stock (the Merger). The Company also paid $20 million in costs to complete the Merger. Simultaneously, KCA and Kansas Gas and Electric Company merged and adopted the name of Kansas Gas and Electric Company (KG&E). The Merger was accounted for as a purchase. For income tax purposes the tax basis of the KG&E assets was not changed by the Merger.

As the Company acquired 100 percent of the common and preferred stock of KG&E, the Company recorded an acquisition premium of $490 million on the consolidated balance sheet for the difference in purchase price and book value. This acquisition premium and related income tax requirement of $294 million under SFAS 109 have been classified as plant acquisition adjustment in electric plant in service on the consolidated balance sheets. The total cost of the acquisition was $1.066 billion. Under the provisions of orders of the KCC and the MPSC the acquisition premium is recorded as an acquisition adjustment and not allocated to the other assets and liabilities of KG&E.

In the November 1991 KCC order approving the Merger, a mechanism was approved to share equally between the shareholders and ratepayers the cost savings generated by the Merger in excess of the revenue requirement needed to allow recovery of the amortization of a portion of the acquisition adjustment, including income tax, calculated on the basis of a purchase price of KG&E's common stock at $29.50 per share. The order provides an amortization period for the acquisition adjustment of 40 years commencing in August 1995, at which time the full amount of cost savings is expected to have been implemented. Merger savings will be measured by application of an inflation index to certain pre-merger operating and maintenance costs at the time of the next Kansas rate case. While the Company has achieved savings from the Merger, there is no assurance that the savings achieved will be sufficient to, or the cost savings sharing mechanism will operate as to fully offset the amortization of the acquisition adjustment. The order further provides a moratorium on increases, with certain exceptions, in the Company's Kansas electric and natural gas rates until August 1995. The KCC ordered refunds totalling $32 million to the combined companies' customers to share with customers the Merger-related cost savings achieved during the moratorium period. The first refund was made in April 1992 and amounted to $8.5 million. A refund of the same amount was made in December 1993 and an additional refund of $15 million will be made in September 1994.

The KCC order approving the Merger requires the legal reorganization of KG&E so that it is no longer held as a separate subsidiary after January 1, 1995, unless good cause is shown why such separate existence should be maintained. The Securities and Exchange Commission order relating to the Merger granted the Company an exemption under the Public Utilities Holding Company Act until January 1, 1995. In connection with a requested ruling that a merger of KG&E into Western Resources would not adversely affect the tax structure of the merger, KG&E received a response from the Internal Revenue Service that the IRS would not issue the requested ruling. In light of the IRS response, KG&E withdrew its request for a ruling. The Company will consider alternative forms of combination or seek regulatory approvals to waive the requirements for a combination. There is no certainty as to whether a combination will occur or as to the form or timing thereof.

As the Merger did not occur until March 31, 1992, the twelve months ended December 31, 1992, results of operations for the Company reported in its statements of income, cash flows, and common stock equity reflect KG&E's results of operations for only the nine months ended December 31, 1992. The pro forma combined revenues, operating income, net income, and earnings per common share of the Company presented below give effect to the Merger as if it had occurred at January 1, 1991. This pro forma information is not necessarily indicative of the results of operations that would have occurred had the Merger been consummated for the period for which it is being given effect nor is it necessarily indicative of future operating results.

Year Ended December 31,	1992	1991
(Dollars in Thousands, except per share amounts)		
Revenues.	$1,684,885	$1,748,844
Operating Income.	268,772	279,458
Net Income.	131,524	110,290(1)
Earnings Per Common	$ 2.03	$ 1.72(1)

(1) Reflects information before the cumulative effect of the January 1, 1991 change in accounting method of recognizing revenues.

4. COMMITMENTS AND CONTINGENCIES

As part of its ongoing operations and construction program, the Company has commitments under purchase orders and contracts which have an unexpended balance of approximately $86 million at December 31, 1993. Approximately $36 million is attributable to modifications to upgrade the turbines at Jeffrey Energy Center to be completed by December 31, 1998. Plans for future construction of utility plant are discussed in the "Management's Discussion and Analysis" section.

Environmental: The Company has been associated with 28 (20 in Kansas and 8 in Missouri) former manufactured gas sites which may contain coal tar and other potentially harmful materials. These sites were operated decades ago by other companies, and were acquired by the Company after they had ceased operation. The Environmental Protection Agency (EPA) has performed preliminary assessments of eleven of these sites (EPA sites), six of which are under site investigation. The Company has not received any indication from the EPA that further action will be taken at the EPA sites, nor does the Company have reason to believe there will be any fines or penalties assessed related to these sites. The Company and the Kansas Department of Health and Environment (KDHE) entered into a consent agreement to conduct separate preliminary assessments of the 20 former manufactured gas sites located in Kansas. The preliminary assessments of these 20 sites have been completed at a total cost of approximately $500,000. The Company plans to initiate site investigation and risk assessments at the two highest priority sites in 1994 at a total cost of approximately $500,000. Until such time that risk assessments are completed at these or the remaining sites, it will be impossible to predict the cost of remediation. However, the Company is aware of other utilities in Region VII of the EPA (Kansas, Missouri, Nebraska, and Iowa) which have incurred remediation costs for such sites ranging between $500,000 and $10 million, depending on the site. The Company is also aware that the KCC has permitted another Kansas utility to recover a portion of the remediation costs through rates. To the extent that such remediation costs are not recovered through rates, the costs could be material to the Company's financial position or results of operations depending on the degree of remediation and number of years over which the remediation must be completed.

The Company has been identified as one of numerous potentially responsible parties in four hazardous waste sites listed by the EPA as Superfund sites. One site is a groundwater contamination site in Wichita, Kansas, and one is an oil soil contamination site in Springfield, Missouri. The other two sites are solid waste land fills located in Edwardsville and Hutchinson, Kansas. The Company's obligation at these sites appears to be limited, and it is the opinion of the Company's management that the resolution of these matters will not have a material impact on the Company's financial position or results of operations.

As part of the sale of the Company's Missouri Properties to Southern Union, Southern Union assumed responsibility under an agreement for any environmental matters now pending or that may arise after closing. For any environmental matters now pending or discovered within two years of the date of the agreement, and after pursuing several other potential recovery options, the Company may be liable for up to a maximum of $7.5 million under a sharing arrangement with Southern Union provided for in the agreement.

Spent Nuclear Fuel Disposal: Under the Nuclear Waste Policy Act of 1982, the U.S. Department of Energy (DOE) is responsible for the ultimate storage and disposal of spent nuclear fuel removed from nuclear reactors. Under a contract with the DOE for disposal of spent nuclear fuel, the Company pays a quarterly fee to DOE of one mill per kilowatthour on net nuclear generation. These fees are included as part of nuclear fuel expense and amounted to $3.5 million for 1993 and $1.6 million for 1992.

Decommissioning: The Company's share of Wolf Creek decommissioning costs, currently authorized in rates, was estimated to be approximately $97 million in 1988 dollars. Decommissioning costs are being charged to operating expenses. Amounts so expensed are deposited in an external trust fund and will be used solely for the physical decommissioning of the plant. Electric rates charged to customers provide for recovery of these decommissioning costs over the estimated life of Wolf Creek. At December 31, 1993, and December 31, 1992, $13.2 and $9.3 million, respectively, were on deposit in the decommissioning fund. On September 1, 1993, WCNOC filed an application with the KCC for an order approving a 1993 Wolf Creek Decommissioning Cost Study which estimates the Company's share of Wolf Creek decommissioning costs at approximately $174 million in 1993 dollars. If approved by the KCC, management expects substantially all such cost increases to be recovered through the ratemaking process.

The Company carries $164 million in premature decommissioning insurance in the event of a shortfall in the trust fund. The insurance coverage has several restrictions. One of these is that it can only be used if Wolf Creek incurs an accident exceeding $500 million in expenses to safely stabilize the reactor, to decontaminate the reactor and reactor station site in accordance with a plan approved by the Nuclear Regulatory Commission (NRC), and to pay for on-site property damages. If the amount designated as decommissioning insurance is needed to implement the NRC-approved plan for stabilization and decontamination, it would not be available for decommissioning purposes.

Nuclear Insurance: The Price-Anderson Act limits the combined public liability of the owners of nuclear power plants to $9.4 billion for a single nuclear incident. The Wolf Creek owners (Owners) have purchased the maximum available private insurance of $200 million and the balance is provided by an assessment plan mandated by the NRC. Under this plan, the Owners are jointly and severally subject to a retrospective assessment of up to $79.3 million ($37.3 million, Company's share) in the event there is a nuclear incident involving any of the nation's licensed reactors. This assessment is subject to an inflation adjustment based on the Consumer Price Index. There is a limitation of $10 million ($4.7 million, Company's share) in retrospective assessments per incident per year.

The Owners carry decontamination liability, premature decommissioning liability, and property damage insurance for Wolf Creek totalling approximately $2.8 billion ($1.3 billion, Company's share). This insurance is provided by a combination of "nuclear insurance pools" ($1.3 billion) and Nuclear Electric Insurance Limited (NEIL) ($1.5 billion). In the event of an accident, insurance proceeds must first be used for reactor stabilization and site decontamination. The remaining proceeds from the $2.8 billion insurance coverage ($1.3 billion, Company's share), if any, can be used for property damage up to $1.1 billion (Company's share) and premature decommissioning costs up to $117.5 million (Company's share) in excess of funds previously collected for decommissioning (as discussed under "Decommissioning"), with the remaining $47 million (Company's share) available for either property damage or premature decommissioning costs.

The Owners also carry additional insurance with NEIL to cover costs of replacement power and other extra expenses incurred during a prolonged outage resulting from accidental property damage at Wolf Creek. If losses incurred at any of the nuclear plants insured under the NEIL policies exceed premiums, reserves, and other NEIL resources, the Company may be subject to retrospective assessments of approximately $9 million per year.

There can be no assurance that all potential losses or liabilities will be insurable or that the amount of insurance will be sufficient to cover them. Any substantial losses not covered by insurance, to the extent not recoverable through rates, could have a material adverse effect on the Company's financial condition and results of operations.

Clean Air Act: The Clean Air Act Amendments of 1990 (the Act) require a two-phase reduction in sulfur dioxide and nitrous oxide emissions effective in 1995 and 2000 and a probable reduction in toxic emissions. To meet the monitoring and reporting requirements under the acid rain program, the Company is installing continuous monitoring and reporting equipment at a total cost of approximately $10 million. At December 31, 1993, the Company had completed approximately $4 million of these capital expenditures with the remaining $6 million of capital expenditures to be completed in 1994 and 1995. The Company does not expect additional equipment to reduce sulfur emissions to be necessary under Phase II. The Company currently has no Phase I affected units.

The nitrous oxide and toxic limits, which were not set in the law, will be specified in future EPA regulations. The EPA has issued for public comment preliminary nitrous oxide regulations for Phase I group 1 units. Nitrous oxide regulations for Phase II units and Phase I group 2 units are mandated in the Act to be promulgated by January 1, 1997. Although the Company has no Phase I units, the final nitrous oxide regulations for Phase I group 1 may allow for early compliance for Phase II group 1 units. Until such time as the Phase I group 1 nitrous oxide regulations are final, the Company will be unable to determine its compliance options or related compliance costs.

Federal Income Taxes: During 1991, the Internal Revenue Service (IRS) completed an examination of KG&E's federal income tax returns for the years 1984 through 1988. In April 1992, KG&E received the examination report and upon review filed a written protest in August 1992. In October 1993, KG&E received another examination report for the years 1989 and 1990 covering the same issues identified in the previous examination report. Upon review of this report, KG&E filed a written protest in November 1993. The most significant proposed adjustments reduce the depreciable basis of certain assets and investment tax credits generated. Management believes there are significant questions regarding the theory, computations, and sampling techniques used by the IRS to arrive at its proposed adjustments, and also believes any additional tax expense incurred or loss of investment tax credits will not be material to the Company's financial position and results of operations. Additional income tax payments, if any, are expected to be offset by investment tax credit carryforwards, alternative minimum tax credit carryforwards, or deferred tax provisions.

Fuel Commitments: To supply a portion of the fuel requirements for its generating plants, the Company has entered into various commitments to obtain nuclear fuel, coal, and natural gas. Some of these contracts contain provisions for price escalation and minimum purchase commitments. At December 31, 1993, WCNOC's nuclear fuel commitments (Company's share) were approximately $18.0 million for uranium concentrates expiring at various times through 1997, $123.6 million for enrichment expiring at various times through 2014, and $45.5 million for fabrication through 2012. At December 31, 1993, the Company's coal and natural gas contract commitments in 1993 dollars under the remaining term of the contracts were $2.8 billion and $20.4 million, respectively. The largest coal contract was renegotiated early in 1993 and expires in 2020, with the remaining coal contracts expiring at various times through 2013. The majority of natural gas contracts continue through 1995 with automatic one-year extension provisions. In the normal course of business, additional commitments and spot market purchases will be made to obtain adequate fuel supplies.

Energy Act: As part of the 1992 Energy Policy Act, a special assessment is being collected from utilities for a uranium enrichment, decontamination, and decommissioning fund. The Company's portion of the assessment for Wolf Creek is approximately $7 million, payable over 15 years. Management expects such costs to be recovered through the ratemaking process.

5. RATE MATTERS AND REGULATION

The Company, under rate orders from certain state regulatory commissions and the FERC, recovers increases in fuel and natural gas costs through fuel adjustment clauses for wholesale and certain retail electric customers and various purchased gas adjustment clauses (PGA) for natural gas customers. Certain state regulatory commissions require the annual difference between actual gas cost incurred and cost recovered through the application of the PGA be deferred and amortized through rates in subsequent periods.

Elimination of the Energy Cost Adjustment Clause (ECA): On March 26, 1992, in connection with the Merger, the KCC approved the elimination of the ECA for most Kansas retail electric customers of both the Company and KG&E effective April 1, 1992. The provisions for fuel costs included in base rates were established at a level intended by the KCC to equal the projected average cost of fuel through August 1995, and to include recovery of costs provided by previously issued orders relating to coal contract settlements. Any increase or decrease in fuel costs from the projected average will be absorbed by the Company.

MPSC Rate Proceedings: On October 5, 1993, the MPSC approved an agreement among the Company, the MPSC staff, and intervenors to increase natural gas rates $9.75 million annually, effective October 15, 1993. Also on October 15, 1993, the Company discontinued the deferral of service line replacement program costs deferred since July 1, 1991, and began amortizing the balance to expense over twenty years. At December 31, 1993, approximately $8.3 million of these deferrals have been included in other deferred charges on the consolidated balance sheet.

On January 22, 1992, the MPSC issued an order authorizing the Company to increase natural gas rates $7.3 million annually.

KCC Rate Proceedings: On January 24, 1992, the KCC issued an order allowing the Company to continue the deferral of service line replacement program costs incurred since January 1, 1992, including depreciation, property taxes, and carrying costs for recovery in the next general rate case. At December 31, 1993, approximately $2.9 million of these deferrals have been included in other deferred charges on the consolidated balance sheet.

On December 30, 1991, the KCC approved a permanent natural gas rate increase of $39 million annually and the Company discontinued the deferral of accelerated line survey costs on January 1, 1992. Approximately $8.3 million of deferred costs remain in other deferred charges on the consolidated balance sheet at December 31, 1993, with the balance being included in rates and amortized to expense during a 43-month period, commencing January 1, 1992.

Gas Transportation Charges: On September 12, 1991, the KCC authorized the Company to begin recovering, through the PGA, deferred supplier gas transportation costs of $9.9 million incurred through December 31, 1990, based on a three-year amortization schedule. On December 30, 1991, the KCC authorized the Company to recover deferred transportation costs of approximately $2.8 million incurred subsequent to December 31, 1990, through the PGA over a 32-month period. At December 31, 1993, approximately $4.8 million of these deferrals remain in other deferred charges on the consolidated balance sheet.

Tight Sands: In December 1991, the KCC, MPSC, and Oklahoma Corporation Commission (OCC) approved agreements authorizing the Company to refund to customers approximately $40 million of the proceeds of the Tight Sands antitrust litigation settlement to be collected on behalf of Western Resources' natural gas customers. To secure the refund of settlement proceeds, the Commissions authorized the establishment of an independently administered trust to collect and maintain cash receipts received under Tight Sands settlement agreements and provide for the refunds made. The trust has a term of ten years.

Rate Stabilization Plan: In 1988, the KCC issued an order requiring that the accrual of phase-in revenues be discontinued by KG&E effective December 31, 1988. Effective January 1, 1989, KG&E began amortizing the phase-in revenue asset on a straight-line basis over 9 1/2 years.

Coal Contract Settlements: In March 1990, the KCC issued an order allowing KG&E to defer its share of a 1989 coal contract settlement with the Pittsburgh and Midway Coal Mining Company amounting to $22.5 million. This amount was recorded as a deferred charge on the consolidated balance sheets. The settlement resulted in the termination of a long-term coal contract. The KCC permitted KG&E to recover this settlement as follows: 76 percent of the settlement plus a return over the remaining term of the terminated contract (through 2002) and 24 percent to be amortized to expense with a deferred return equivalent to the carrying cost of the asset.

In February 1991, KG&E paid $8.5 million to settle a coal contract lawsuit with AMAX Coal Company and recorded the payment as a deferred charge on the consolidated balance sheet. The KCC approved the recovery of the settlement plus a return, equivalent to the carrying cost of the asset, over the remaining term of the terminated contract (through 1996).

FERC Order No. 528: In 1990, the FERC issued Order No. 528 which authorized new methods for the allocation and recovery of take-or-pay settlement costs by natural gas pipelines from their customers. Settlements have been reached between the Company's two largest gas pipelines and their customers in FERC proceedings related to take-or-pay issues. The settlements address the allocation of take-or-pay settlement costs between the pipelines and their customers. However, the amount which one of the pipelines will be allowed to recover is yet to be determined. Litigation continues between the Company and a former upstream pipeline supplier to one of the Company's pipeline suppliers concerning the amount of such costs which may ultimately be allocated to the Company's pipeline supplier. A portion of any costs allocated to the Company's pipeline supplier will be charged to the Company. Due to the uncertainty concerning the amount to be recovered by the Company's current suppliers and of the outcome of the litigation between the Company and its current pipeline's upstream supplier, the Company is unable to estimate its future liability for take-or-pay settlement costs. However, the KCC and MPSC have approved mechanisms which are expected to allow the Company to recover these take-or-pay costs from its customers.

6. EMPLOYEE BENEFIT PLANS

Pension: The Company maintains noncontributory defined benefit pension plans covering substantially all employees. Pension benefits are based on years of service and the employee's compensation during the five highest paid consecutive years out of ten before retirement. The Company's policy is to fund pension costs accrued, subject to limitations set by the Employee Retirement Income Security Act of 1974 and the Internal Revenue Code.

The following tables provide information on the components of pension cost, funded status, and actuarial assumptions for the Company's pension plans:

Year Ended December 31,	1993	1992	1991
	(Dollars in Thousands)		
Pension Cost:			
Service cost..................	$ 9,778	$ 9,847	$ 6,589
Interest cost on projected benefit obligation..........	35,688	29,457	20,985
Return on plan assets..........	(64,113)	(38,967)	(59,161)
Deferred gain on plan assets...	29,190	7,705	38,015
Net amortization...............	(669)	(948)	(131)
Net pension cost...........	$ 9,874	$ 7,094	$ 6,297

December 31,	1993	1992	1991
	(Dollars in Thousands)		
Funded Status:			
Actuarial present value of benefit obligations:			
Vested	$353,023	$316,100	$200,435
Non-vested	26,983	19,331	13,935
Total.	$380,006	$335,431	$214,370
Plan assets (principally debt and equity securities) at fair value	$490,339	$452,372	$324,780
Projected benefit obligation . . .	468,996	424,232	282,062
Plan assets in excess of projected benefit obligation . .	21,343	28,140	42,718
Unrecognized transition asset. . .	(2,756)	(3,092)	(1,253)
Unrecognized prior service costs .	64,217	55,886	27,216
Unrecognized net gain.	(108,783)	(106,486)	(69,494)
Accrued pension costs.	$(25,979)	$(25,552)	$ (813)

Year Ended December 31,	1993	1992	1991
Actuarial Assumptions:			
Discount rate.	7.0-7.75%	8.0-8.5%	8.0%
Annual salary increase rate. . .	5.0 %	6.0%	6.0%
Long-term rate of return	8.0-8.5 %	8.0-8.5%	8.0%

Retirement and Voluntary Separation Plans: In January 1992, the Board of Directors approved early retirement plans and voluntary separation programs. The voluntary early retirement plans were offered to all vested participants in the Company's defined pension plan who reached the age of 55 with 10 or more years of service on or before May 1, 1992. Certain pension plan improvements were made, including a waiver of the actuarial reduction factors for early retirement and a cash incentive payable as a monthly supplement up to 60 months or as a lump sum payment. Of the 738 employees eligible for the early retirement option, 531, representing ten percent of the combined Company's work force, elected to retire on or before the May 1, 1992, deadline. Seventy-one of those electing to retire were employees of KG&E acquired March 31, 1992 (see Note 3). Another 67 employees, with 10 or more years of service, elected to participate in the voluntary separation program. Of those, 29 were employees of KG&E. In addition, 68 employees received Merger-related severance benefits, including 61 employees of KG&E. The actuarial cost, based on plan provisions for early retirement and voluntary separation programs, and Merger-related severance benefits for the KG&E employees, were considered in purchase accounting for the Merger. The actuarial cost of the former Kansas Power and Light Company employees, of approximately $11 million, was expensed in 1992.

Postretirement: The Company adopted the provisions of Statement of Financial Accounting Standards No. 106 (SFAS 106) in the first quarter of 1993. This statement requires the accrual of postretirement benefits other than pensions, primarily medical benefit costs, during the years an employee provides service.

Based on actuarial projections and adoption of the transition method of implementation which allows a 20-year amortization of the accumulated benefit obligation, the annual expense under SFAS 106 was approximately $26.5 million in 1993 (as compared to approximately $9.6 million on a cash basis) and the Company's total obligation was approximately $166.5 million at December 31, 1993. To mitigate the impact of SFAS 106 expense, the Company has implemented programs to reduce health care costs. In addition, the Company has received orders from the KCC and MPSC permitting the initial deferral of SFAS 106 expense. To mitigate the impact SFAS 106 expense will have on rate increases, the Company will include in the future computation of cost of service the actual SFAS 106 expense and an income stream generated from corporate-owned life insurance (COLI). To the extent SFAS 106 expense exceeds income from the COLI program, this excess will be deferred (as allowed by the FASB Emerging Issues Task Force Issue No. 92-12) and offset by income generated through the deferral period by the COLI program. The OCC is reviewing the Company's application for similar treatment in Oklahoma. Should the OCC require recognition of postretirement benefit costs for regulatory purposes under a different method than that proposed under the Company's application, the impact on earnings would not be material. Should the income stream generated by the COLI program not be sufficient to offset the deferred SFAS 106 expense, the KCC and MPSC orders allow recovery of such deficit through the ratemaking process.

Prior to the adoption of SFAS 106 the Company's policy was to recognize the cost of retiree health care and life insurance benefits as expense when claims and premiums for life insurance policies were paid. The cost of providing health care and life insurance benefits to 2,928 retirees was $8.1 million in 1992.

The following table summarizes the status of the Company's postretirement plans for financial statement purposes and the related amount included in the consolidated balance sheet:

December 31,	1993
	(Dollars in Thousands)
Actuarial present value of postretirement benefit obligations:	
Retirees.	$ 111,499
Active employees fully eligible	11,848
Active employees not fully eligible	43,109
Unrecognized prior service cost	18,195
Unrecognized transition obligation.	(160,731)
Unrecognized net loss	(7,100)
Balance sheet liability	$ 16,820

For measurement purposes, an annual health care cost growth rate of 13% was assumed for 1994, decreasing to 6% by 2002 and thereafter. The accumulated post retirement benefit obligation was calculated using a weighted-average discount rate of 7.75%, a weighted-average compensation increase rate of 5.0%, and a weighted-average expected rate of return of 8.5%. The health care cost trend rate has a significant effect on the projected benefit obligation. Increasing the trend rate by 1% each year would increase the present value of the accumulated projected benefit obligation by $11.1 million and the aggregate of the service and interest cost components by $1.5 million.

Postemployment: The FASB has issued Statement of Financial Accounting Standards No. 112 (SFAS 112), which establishes accounting and reporting standards for postemployment benefits. The new statement will require the Company to recognize the liability to provide postemployment benefits when the liability has been incurred. The Company adopted SFAS 112 effective January 1, 1994. To mitigate the impact adopting SFAS 112 will have on rate increases, the Company will file applications with the KCC and OCC for orders permitting the initial deferral of SFAS 112 transition costs and expenses and its inclusion in the future computation of cost of service net of an income stream generated from COLI. However, if the state regulatory commissions were to recognize postemployment benefit costs under a different method, 1994 earnings could be impacted negatively. At December 31, 1993, the Company estimates SFAS 112 liability to total approximately $11 million.

Savings: The Company maintains savings plans in which substantially all employees participate. The Company matches employees' contributions up to specified maximum limits. The funds of the plans are deposited with a trustee and invested at each employee's option in one or more investment funds, including a Company stock fund. The Company's contributions were $5.4, $5.4, and $3.3 million for 1993, 1992, and 1991, respectively.

Missouri Property Sale: Effective January 31, 1994, the Company transferred a portion of the assets and liabilities of the Company's pension plan to a pension plan established by Southern Union. The amount of assets transferred equal the projected benefit obligation for employees and retirees associated with Southern Union's portion of the Missouri Properties plus an additional $9 million.

7. FAIR VALUE OF FINANCIAL INSTRUMENTS

The following methods and assumptions were used to estimate the fair value of each class of financial instruments for which it is practicable to estimate that value as set forth in Statement of Financial Accounting Standards No. 107:

Cash and Cash Equivalents-
The carrying amount approximates the fair value because of the short-term maturity of these investments.

Decommissioning Trust-
The fair value of the decommissioning trust is based on quoted market prices at December 31, 1993 and 1992.

Variable-rate Debt-
The carrying amount approximates the fair value because of the short-term variable rates of these debt instruments.

Fixed-rate Debt-
The fair value of the fixed-rate debt is based on the sum of the estimated value of each issue taking into consideration the interest rate, maturity, and redemption provisions of each issue.

Redeemable Preference Stock-
The fair value of the redeemable preference stock is based on the sum of the estimated value of each issue taking into consideration the dividend rate, maturity, and redemption provisions of each issue.

The estimated fair values of the Company's financial instruments are as follows:

	Carrying Value		Fair Value	
December 31,	1993	1992	1993	1992
	(Dollars in Thousands)			
Cash and cash equivalents.	$ 1,217	$ 875	$ 1,217	$ 875
Decommissioning trust. . .	13,204	9,272	13,929	9,500
Variable-rate debt	931,352	758,449	931,352	758,449
Fixed-rate debt.	1,364,886	1,508,077	1,473,569	1,563,375
Redeemable preference stock.	150,000	152,733	160,780	161,733

8. LONG-TERM DEBT

The amount of first mortgage bonds authorized by the Western Resources Mortgage and Deed of Trust, dated July 1, 1939, as supplemented, is unlimited. The amount of first mortgage bonds authorized by the KG&E Mortgage and Deed of Trust, dated April 1, 1940, as supplemented, is limited to a maximum of $2 billion. Amounts of additional bonds which may be issued are subject to property, earnings, and certain restrictive provisions of each Mortgage.

On January 20, 1994, KG&E issued $100 million of First Mortgage Bonds, 6.20% Series due January 15, 2006.

On January 31, 1994, the Company redeemed the remaining $2,466,000 principal amount of Gas Service Company (GSC) 8 1/2% Series First Mortgage Bonds due 1997. In addition, the Company took measures to have the GSC Mortgage and Deed of Trust discharged.

Debt discount and expenses are being amortized over the remaining lives of each issue. The Western Resources and KG&E improvement and maintenance fund requirements for certain first mortgage bond series can be met by bonding additional property. The sinking fund requirements for certain Western Resources and KG&E pollution control series bonds can be met only through the acquisition and retirement of outstanding bonds. Bonds maturing and acquisition and retirement of bonds for sinking fund requirements for the five years subsequent to December 31, 1993, are as follows:

Year	Maturing Bonds	Retiring Bonds
	(Dollars in Thousands)	
1994.	$ 2,466	$ 738
1995.	-	753
1996.	16,000	770
1997.	-	1,333
1998.	-	1,550

Long-term debt outstanding at December 31, 1993 and 1992, was as follows:

	1993	1992
	(Dollars in Thousands)	
Western Resources		
First mortgage bond series:		
9.35 % due 1998.	$ -	$ 75,000
7 1/4% due 1999.	125,000	125,000
7 5/8% due 1999.	19,000	19,000
8 3/4% due 2000.	-	20,000
8 7/8% due 2000.	75,000	75,000
7 1/4% due 2002.	100,000	100,000
8 5/8% due 2005.	-	35,000
8 1/8% due 2007.	30,000	30,000
8 3/4% due 2008.	-	35,000
8 5/8% due 2017.	50,000	50,000
8 1/2% due 2022.	125,000	125,000
7.65% due 2023.	100,000	-
	624,000	689,000
Pollution control bond series:		
5.90 % due 2007.	31,000	31,500
6 3/4% due 2009.	45,000	45,000
9 5/8% due 2013.	-	58,500
6% due 2033.	58,500	-
	134,500	135,000
KG&E		
First mortgage bond series:		
5 5/8% due 1996.	16,000	16,000
8 1/8% due 2001.	-	35,000
7 3/8% due 2002.	-	25,000
7.60% due 2003.	135,000	135,000
6 1/2% due 2005.	65,000	-
8 3/8% due 2006.	-	25,000
8 1/2% due 2007.	-	25,000
8 7/8% due 2008.	-	30,000
	216,000	291,000
Pollution control bond series:		
6.80% due 2004.	14,500	14,500
5 7/8% due 2007.	21,940	21,940
6% due 2007.	10,000	10,000
7.0% due 2031.	327,500	327,500
	373,940	373,940
GSC		
First mortgage bond series:		
8 1/2% due 1997.	2,466	4,932
	2,466	4,932
Bank term loan	-	230,000
Other pollution control obligations. . . .	13,980	14,205
Revolving credit agreement	115,000	150,000
Other long term agreement.	53,913	46,640
Less:		
Unamortized debt discount.	6,607	6,730
Long-term debt due within one year . . .	3,204	1,961
	$1,523,988	$1,926,026

In January 1993, the Company renegotiated its $600 million bank term loan and revolving credit facility used to finance the Merger into a $350 million revolving credit facility, secured by KG&E common stock. The revolver has an initial term of three years with options to renew for an additional two years with the consent of the banks. The unused portion of the revolving credit facility may be used to provide support for outstanding short-term debt. At December 31, 1993, $115 million was outstanding under the facility.

On September 20, 1993, KG&E terminated a long-term revolving credit agreement which provided for borrowings of up to $150 million. The loan agreement, which was effective through October 1994, was repaid without penalty.

KG&E has a long-term agreement, expiring in 1995, which contains provisions for the sale of accounts receivable and unbilled revenues (receivables) and phase-in revenues up to a total of $180 million. Amounts related to receivables are accounted for as sales while those related to phase-in revenues are accounted for as collateralized borrowings. Additional receivables are continually sold to replace those collected. At December 31, 1993 and 1992, outstanding receivables amounting to $56.8 and $47.7 million, respectively, were considered sold under the agreement. The credit risk associated with the sale of customer accounts receivable is considered minimal. The weighted average interest rate, including fees, was 3.7% for the year ended December 31, 1993, and 6.6% for the nine months ended December 31,

1992. At December 31, 1993, an additional $16.4 million was available under the agreement.

9. SHORT-TERM DEBT

The Company's short-term financing requirements are satisfied, as needed, through the sale of commercial paper, short-term bank loans and borrowings under other unsecured lines of credit maintained with banks. Information concerning these arrangements for the years ended December 31, 1993, 1992, and 1991, is set forth below:

Year Ended December 31,	1993	1992	1991
		(Dollars in Thousands)	
Lines of credit at year end. . . .	$145,000	$250,000(1)	$185,000(2)
Short-term debt outstanding at year end	440,895	222,225	135,800
Weighted average interest rate on debt outstanding at year end (including fees)	3.67%	4.70%	5.07%
Maximum amount of short-term debt outstanding during the period.	$443,895	$263,900	$175,000
Monthly average short-term debt. .	347,278	179,577	125,968
Weighted daily average interest rates during the year (including fees)	3.44%	4.90%	6.69%

(1) Decreased to $155 million in January 1993.
(2) Increased to $200 million in January 1992.

In connection with the commitments, the Company has agreed to pay certain fees to the banks. Available lines of credit and the unused portion of the revolving credit facility are utilized to support the Company's outstanding short-term debt.

10. LEASES

At December 31, 1993, the Company had leases covering various property and equipment. Certain lease agreements meet the criteria, as set forth in Statement of Financial Accounting Standards No. 13, for classification as capital leases.

Rental payments for capital and operating leases and estimated rental commitments are as follows:

Year Ending December 31,	Capital Leases	Operating Leases
	(Dollars in Thousands)	
1991	$ 1,217	$21,501
1992	2,426	52,701
1993	3,272	55,011
Future Commitments:		
1994	$ 4,002	$47,729
1995	3,752	45,825
1996	3,627	44,176
1997	1,209	41,644
1998	-	41,019
Thereafter	-	771,157
Total	$12,590	$ 991,550
Less Interest	1,466	
Net obligation	$11,124	

In 1987, KG&E sold and leased back its 50 percent undivided interest in La Cygne 2. The lease has an initial term of 29 years, with various options to renew the lease or repurchase the 50 percent undivided interest. KG&E remains responsible for its share of operation and maintenance costs and other related operating costs of La Cygne 2. The lease is an operating lease for financial reporting purposes.

As permitted under the lease agreement, the Company in 1992 requested the Trustee Lessor to refinance $341.1 million of secured facility bonds of the Trustee and owner of La Cygne 2. The transaction was requested to reduce recurring future net lease expense. In connection with the refinancing on September 29, 1992, a one-time payment of approximately $27 million was made by the Company which has been deferred and is being amortized over the remaining life of the lease and included in operating expense as part of the future
lease expense.

Future minimum annual lease payments, included in the table above, required under the lease agreement are approximately $34.6 million for each year through 1998 and $715 million over the remainder of the lease.

The gain of approximately $322 million realized at the date of the sale has been deferred for financial reporting purposes, and is being amortized over the initial lease term in proportion to the related lease expense. KG&E's lease expense, net of amortization of the deferred gain and a one-time payment, was approximately $22.5 million for the year ended December 31, 1993, and $20.6 million for the nine months ended December 31, 1992.

11. JOINT OWNERSHIP OF UTILITY PLANTS

Company's Ownership at December 31, 1993

	In-Service Dates	Invest- ment	Accumulated Depreciation	Net (MW)	Per- cent
		(Dollars in Thousands)			
La Cygne 1 (a)	Jun 1973	$ 150,265	$ 91,175	342	50
Jeffrey 1 (b)	Jul 1978	277,087	116,526	587	84
Jeffrey 2 (b)	May 1980	274,018	106,301	566	84
Jeffrey 3 (b)	May 1983	386,925	124,158	588	84
Wolf Creek (c)	Sep 1985	1,366,387	281,819	533	47

(a) Jointly owned with Kansas City Power & Light Company (KCPL)
(b) Jointly owned with UtiliCorp United Inc. and a third party
(c) Jointly owned with KCPL and Kansas Electric Power Cooperative, Inc.

Amounts and capacity represent the Company's share. The Company's share of operating expenses of the plants in service above, as well as such expenses for a 50 percent undivided interest in La Cygne 2 (representing 335 MW capacity) sold and leased back to the Company in 1987, are included in operating expenses in the statements of income. The Company's share of other transactions associated with the plants is included in the appropriate classification in the Company's consolidated financial statements.

12. INCOME TAXES

The Company adopted the provisions of SFAS 109 in the first quarter of 1992. KG&E adopted the provisions of SFAS 96 in 1987 and SFAS 109 in 1992. These statements require the Company to establish deferred tax assets and liabilities, as appropriate, for all temporary differences, and to adjust deferred tax balances to reflect changes in tax rates expected to be in effect during the periods the temporary differences reverse.

In accordance with various rate orders received from the KCC, the MPSC, and the OCC, the Company has not yet collected through rates the amounts necessary to pay a significant portion of the net deferred income tax liabilities. As management believes it is probable that the net future increases in income taxes payable will be recovered from customers through future rates, it has recorded a deferred asset for these amounts. These assets are also a temporary difference for which deferred income tax liabilities have been provided. Accordingly, the adoption of SFAS 109 did not have a material impact on the Company's results of operations.

At December 31, 1993, KG&E has unused investment tax credits of approximately $7.1 million available for carryforward which, if not utilized, will expire in the years 2000 through 2002. In addition, the Company has alternative minimum tax credits generated prior to April 1, 1992, which carryforward without expiration, of $57.2 million which may be used to offset future regular tax to the extent the regular tax exceeds the alternative minimum tax. These credits have been applied in determining the Company's net deferred income tax liability and corresponding deferred future income taxes at December 31, 1993.

Deferred income taxes result from temporary differences between the financial statement and tax basis of the Company's assets and liabilities. The sources of these differences and their cumulative tax effects are as follows:

December 31,		1993	
	Debits	Credits	Total
	(Dollars in Thousands)		
Sources of Deferred Income Taxes:			
Accelerated depreciation and other property items	$ -	$ (647,202)	$ (647,202)
Energy and purchased gas adjustment clauses	2,452	-	2,452
Phase-in revenues.	-	(35,573)	(35,573)
Natural gas line survey and replacement program.	-	(7,721)	(7,721)
Deferred gain on sale-leaseback. .	116,186	-	116,186
Alternative minimum tax credits. .	39,882	-	39,882
Deferred coal contract settlements.	-	(14,980)	(14,980)
Deferred compensation/pension liability.	11,301	-	11,301
Acquisition premium.	-	(301,394)	(301,394)
Deferred future income taxes . . .	-	(117,549)	(117,549)
Other.	-	(14,039)	(14,039)
Total Deferred Income Taxes.	$ 169,821	$(1,138,458)	$ (968,637)

December 31,	1992		
	Debits	Credits	Total
	(Dollars in Thousands)		
Sources of Deferred Income Taxes:			
Accelerated depreciation and other property items	$ -	$ (607,303)	$ (607,303)
Energy and purchased gas adjustment clauses	-	(7,717)	(7,717)
Phase-in revenues.	-	(37,564)	(37,564)
Natural gas line survey and replacement program.	-	(7,473)	(7,473)
Deferred gain on sale-leaseback. .	104,573	-	104,573
Alternative minimum tax credits. .	39,882	-	39,882
Deferred coal contract settlements.	-	(9,318)	(9,318)
Deferred compensation/pension liability.	8,488	-	8,488
Acquisition premium.	-	(314,241)	(314,241)
Deferred future income taxes . . .	-	(158,102)	(158,102)
Other.	-	(1,380)	(1,380)
Total Deferred Income Taxes.	$ 152,943	$(1,143,098)	$ (990,155)

13. SEGMENTS OF BUSINESS

The Company is a public utility engaged in the generation, transmission, distribution, and sale of electricity in Kansas and the transportation, distribution, and sale of natural gas in Kansas, Missouri, and Oklahoma.

Year Ended December 31,	1993	1992(1)	1991
	(Dollars in Thousands)		
Operating revenues:			
Electric.	$1,104,537	$ 882,885	$ 471,839
Natural gas	804,822	673,363	690,339
	1,909,359	1,556,248	1,162,178
Operating expenses excluding income taxes:			
Electric.	791,563	632,169	337,150
Natural gas	747,755	642,910	664,825
	1,539,318	1,275,079	1,001,975
Income taxes:			
Electric.	73,425	41,184	32,239
Natural gas	4,553	816	(1,657)
	77,978	42,000	30,582
Operating income:			
Electric.	239,549	209,532	102,450
Natural gas	52,514	29,637	27,171
	$ 292,063	$ 239,169	$ 129,621
Identifiable assets at December 31:			
Electric.	$4,231,277	$4,390,117	$1,196,023
Natural gas	1,040,513	918,729	840,692
Other corporate assets(2) . .	140,258	130,060	75,798
	$5,412,048	$5,438,906	$2,112,513
Other Information--			
Depreciation and amortization:			
Electric.	$ 126,034	$ 105,842	$ 53,632
Natural gas	38,330	38,171	32,103
	$ 164,364	$ 144,013	$ 85,735
Maintenance:			
Electric.	$ 87,696	$ 73,104	$ 34,240
Natural gas	30,147	28,507	26,275
	$ 117,843	$ 101,611	$ 60,515
Capital expenditures:			
Electric.	$ 137,874	$ 95,465	$ 43,714
Nuclear fuel.	5,702	15,839	-
Natural gas	94,055	91,189	81,961
	$ 237,631	$ 202,493	$ 125,675

(1)Information reflects the merger with KG&E on March 31, 1992.
(2)Principally cash, temporary cash investments, non-utility assets, and deferred charges.

The portion of the table above related to the Missouri Properties is as follows (unaudited):

	1993 (Dollars in Thousands)
Natural gas revenues.	$ 349,749
Operating expenses excluding income taxes.	326,329
Income taxes.	2,672
Operating income.	20,748
Identifiable assets	398,464
Depreciation and amortization	12,668
Maintenance	10,504
Capital expenditures.	38,821

14. COMMON STOCK AND CUMULATIVE PREFERRED AND PREFERENCE STOCK

The Company's Restated Articles of Incorporation, as amended, provides for 85,000,000 authorized shares of common stock. During 1993, the Company issued 3,572,323 shares of common stock and at December 31, 1993, 61,617,873 shares were outstanding.

Not subject to mandatory redemption: The cumulative preferred stock is redeemable in whole or in part on 30 to 60 days notice at the option of the Company.

Subject to mandatory redemption: On October 1, 1993, the Company redeemed the remaining 22,000 shares of the 8.70% Series preference stock.

The mandatory sinking fund provisions of the 8.50% Series preference stock require the Company to redeem 50,000 shares annually beginning on July 1, 1997, at $100 per share. The Company may, at its option, redeem up to an additional 50,000 shares on each July 1, at $100 per share. The 8.50% Series also is redeemable in whole or in part, at the option of the Company, subject to certain restrictions on refunding, at a redemption price of $107.37, $106.80, and $106.23 per share beginning July 1, 1993, 1994, and 1995, respectively.

The mandatory sinking fund provisions of the 7.58% Series preference stock require the Company to redeem 25,000 shares annually beginning on April 1, 2002, and each April 1 through 2006 and the remaining shares on April 1, 2007, all at $100 per share. The Company may, at its option, redeem up to an additional 25,000 shares on each April 1 at $100 per share. The 7.58% Series also is redeemable in whole or in part, at the option of the Company, subject to certain restrictions on refunding, at a redemption price of $106.82, $106.06, and $105.31 per share beginning April 1, 1993, 1994, and 1995, respectively.

15. LEGAL PROCEEDINGS

The Company and its subsidiaries are involved in various legal and environmental proceedings. Management believes that adequate provision has been made within the consolidated financial statements for these matters and accordingly believes their ultimate dispositions will not have a material adverse effect upon the business, financial position, or results of operations of the Company.

16. QUARTERLY RESULTS (UNAUDITED)

The amounts in the table are unaudited but, in the opinion of management, contain all adjustments (consisting only of normal recurring adjustments) necessary for a fair presentation of the results of such periods. The business of the Company is seasonal in nature and, in the opinion of management, comparisons between the quarters of a year do not give a true indication of overall trends and changes in operations.

	First	Second	Third	Fourth
	(Dollars in Thousands, except Per Share Amounts)			
1993				
Operating revenues.	$579,581	$400,411	$419,018	$510,349
Operating income.	85,950	60,282	81,225	64,606
Net income.	54,814	30,723	56,807	35,026
Earnings applicable to				
common stock.	51,468	27,320	53,405	31,671
Earnings per share.	$ 0.89	$ 0.47	$ 0.90	$ 0.51
Dividends per share	$ 0.485	$ 0.485	$ 0.485	$ 0.485
Average common shares				
outstanding	58,046	58,046	59,441	61,603
Common stock price:				
High.	$ 35 3/4	$ 36 1/8	$ 37 1/4	$ 37
Low	$ 30 3/8	$ 32 3/4	$ 35	$ 32 3/4
1992(1)				
Operating revenues.	$373,620	$341,715	$380,745	$460,168
Operating income.	42,684	45,830	77,010	73,645
Net income.	27,984	18,434	42,185	39,281
Earnings applicable to				
common stock.	25,472	15,113	38,726	35,822
Earnings per share.	$ 0.74	$ 0.26	$ 0.67	$ 0.62
Dividends per share	$ 0.475	$ 0.475	$ 0.475	$ 0.475
Average common shares				
outstanding	34,566	58,046	58,046	58,046
Common stock price:				
High.	$ 29 1/2	$ 26 7/8	$ 30 1/2	$ 32 5/8
Low	$ 25 3/8	$ 25 1/4	$ 26 3/4	$ 28 1/2

(1) Information reflects the merger with KG&E on March 31, 1992.

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

None.

PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

The information relating to the Company's Directors required by Item 10 is set forth in the Company's definitive proxy statement for its 1994 Annual Meeting of Shareholders to be filed with the Commission. Such information is incorporated herein by reference to the material appearing under the caption Election of Directors in the proxy statement to be filed by the Company with the Commission. See EXECUTIVE OFFICERS OF THE COMPANY on page 18 for the information relating to the Company's Executive Officers as required by Item 10.

ITEM 11. EXECUTIVE COMPENSATION

The information required by Item 11 is set forth in the Company's definitive proxy statement for its 1994 Annual Meeting of Shareholders to be filed with the Commission. Such information is incorporated herein by reference to the material appearing under the captions Information Concerning the Board of Directors, Executive Compensation, Compensation Plans, and Human Resources Committee Report in the proxy statement to be filed by the Company with the Commission.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

The information required by Item 12 is set forth in the Company's definitive proxy statement for its 1994 Annual Meeting of Shareholders to be filed with the Commission. Such information is incorporated herein by reference to the material appearing under the caption Beneficial Ownership of Voting Securities in the proxy statement to be filed by the Company with the Commission.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

The information required by Item 13 is set forth in the Company's definitive proxy statement for its 1994 Annual Meeting of Shareholders to be filed with the Commission. Such information is incorporated herein by reference to the material appearing under the caption Transactions with Management in the proxy statement to be filed by the Company with the Commission.

PART IV

ITEM 14. EXHIBITS, FINANCIAL STATEMENT SCHEDULES, AND REPORTS ON FORM 8-K

The following financial statements are included herein.

FINANCIAL STATEMENTS

Report of Independent Public Accountants
Consolidated Balance Sheets - December 31, 1993 and 1992
Consolidated Statements of Income - years ended December 31, 1993, 1992 and 1991
Consolidated Statements of Cash Flows - years ended December 31, 1993, 1992 and 1991
Consolidated Statements of Taxes - years ended December 31, 1993, 1992 and 1991
Consolidated Statements of Capitalization - December 31, 1993 and 1992
Consolidated Statements of Common Stock Equity - years ended December 31, 1993, 1992 and 1991
Notes to Consolidated Financial Statements

The following supplemental schedules are included herein.

SCHEDULES

Schedule V - Utility Plant - years ended December 31, 1993, 1992 and 1991
Schedule VI - Accumulated Depreciation of Utility Plant - years ended December 31, 1993, 1992 and 1991

Schedules omitted as not applicable or not required under the Rules of regulation S-X: I, II, III, IV, VII, VIII, IX, X, XI, XII, and XIII

REPORTS ON FORM 8-K

Form 8-K dated February 2, 1994

EXHIBIT INDEX

All exhibits marked "I" are incorporated herein by reference.

	Description	
3(a)	-Restated Articles of Incorporation of the Company, as amended May 25, 1988. (filed as Exhibit 4 to Registration Statement No. 33-23022)	I
3(b)	-Certificate of Correction to Restated Articles of Incorporation. (filed as Exhibit 3(b) to the December 1991 Form 10-K)	I
3(c)	-By-laws of the Company, as amended July 15, 1987. (filed as Exhibit 3(d) to the December 1987 Form 10-K)	I
3(d)	-Certificate of Designation of Preference Stock, 8.50% Series, without par value. (filed electronically)	
3(e)	-Certificate of Designation of Preference Stock, 7.58% Series, without par value. (filed electronically)	
4(a)	-Mortgage and Deed of Trust dated July 1, 1939 between the Company and Harris Trust and Savings Bank, Trustee. (filed as Exhibit 4(a) to Registration Statement No. 33-21739)	I
4(b)	-First through Fifteenth Supplemental Indentures dated July 1, 1939, April 1, 1949, July 20, 1949, October 1, 1949, December 1, 1949, October 4, 1951, December 1, 1951, May 1, 1952, October 1, 1954, September 1, 1961, April 1, 1969, September 1, 1970, February 1, 1975, May 1, 1976 and April 1, 1977, respectively. (filed as Exhibit 4(b) to Registration Statement No. 33-21739)	I
4(c)	-Sixteenth Supplemental Indenture dated June 1, 1977. (filed as Exhibit 2-D to Registration Statement No. 2-60207)	I
4(d)	-Seventeenth Supplemental Indenture dated February 1, 1978. (filed as Exhibit 2-E to Registration Statement No. 2-61310)	I
4(e)	-Eighteenth Supplemental Indenture dated January 1, 1979. (filed as Exhibit (b) (1)-9 to Registration Statement No. 2-64231)	I
4(f)	-Nineteenth Supplemental Indenture dated May 1, 1980. (filed as Exhibit 4(f) to Registration Statement No. 33-21739)	I
4(g)	-Twentieth Supplemental Indenture dated November 1, 1981. (filed as Exhibit 4(g) to Registration Statement No. 33-21739)	I
4(h)	-Twenty-First Supplemental Indenture dated April 1, 1982. (filed as Exhibit 4(h) to Registration Statement No. 33-21739)	I
4(i)	-Twenty-Second Supplemental Indenture dated February 1, 1983. (filed as Exhibit 4(i) to Registration Statement No. 33-21739)	I
4(j)	-Twenty-Third Supplemental Indenture dated July 2, 1986. (filed as Exhibit 4(j) to Registration Statement No. 33-12054)	I
4(k)	-Twenty-Fourth Supplemental Indenture dated March 1, 1987. (filed as Exhibit 4(k) to Registration Statement No. 33-21739)	I
4(l)	-Twenty-Fifth Supplemental Indenture dated October 15, 1988. (filed as Exhibit 4 to the September 1988 Form 10-Q)	I
4(m)	-Twenty-Sixth Supplemental Indenture dated February 15, 1990. (filed as Exhibit 4(m) to the December 1989 Form 10-K)	I
4(n)	-Twenty-Seventh Supplemental Indenture dated March 12, 1992. (filed as exhibit 4(n) to the December 1991 Form 10-K)	I
4(o)	-Twenty-Eighth Supplemental Indenture dated July 1, 1992. (filed as exhibit 4(o) to the December 1992 Form 10-K)	I
4(p)	-Twenty-Ninth Supplemental Indenture dated August 20, 1992. (filed as exhibit 4(p) to the December 1992 Form 10-K)	I

Exhibit	Description	
4(q)	-Thirtieth Supplemental Indenture dated February 1, 1993. (filed as exhibit 4(q) to the December 1992 Form 10-K)	I
4(r)	-Thirty-First Supplemental Indenture dated April 15, 1993. (filed as exhibit 4(r) to Form S-3, Registration Statement No. 33-50069)	I

Instruments defining the rights of holders of other long-term debt not required to be filed as exhibits will be furnished to the Commission upon request.

10(a)	-Agreement between the Company and AMAX Coal West Inc. effective March 31, 1993. (filed electronically)	
10(b)	-Agreement between the Company and Williams Natural Gas Company dated October 1, 1993. (filed electronically)	
10(c)	-Agreement between the Company and Williams Natural Gas Company dated October 1, 1993. (filed electronically)	
10(d)	-Agreement between the Company and Williams Natural Gas Company dated October 1, 1993. (filed electronically)	
10(e)	-Executive Salary Continuation Plan of The Kansas Power and Light Company, as revised, effective May 3, 1988. (filed as Exhibit 10(b) to the September 1988 Form 10-Q)	I
10(f)	-Letter of Agreement between The Kansas Power and Light Company and John E. Hayes, Jr., dated November 20, 1989. (filed as Exhibit 10(w) to the December 1989 Form 10-K)	I
10(g)	-Amended Agreement and Plan of Merger by and among The Kansas Power and Light Company, KCA Corporation, and Kansas Gas and Electric Company, dated as of October 28, 1990, as amended by Amendment No. 1 thereto, dated as of January 18, 1991. (filed as Annex A to Registration Statement No. 33-38967)	I
10(h)	-Deferred Compensation Plan	
10(i)	-Long-term Incentive Plan	
10(j)	-Short-term Incentive Plan	
10(k)	-Outside Directors' Deferred Compensation Plan	
12	-Computation of Ratio of Consolidated Earnings to Fixed Charges. (filed electronically)	
16	-Letter re Change in Certifying Accountant. (filed as Exhibit 16 to the Current Report on Form 8-K dated March 8, 1993)	I
21	-Subsidiaries of the Registrant. (filed as Exhibit 22 to the December 1992 Form 10-K)	I
23(a)	-Consent of Independent Public Accountants, Arthur Andersen & Co. (filed electronically)	
23(b)	-Consent of Independent Public Accountants, Deloitte & Touche (filed electronically))	
23(c)	-Consent of K&A Energy Consultants, Inc. (filed as Exhibit 24(b) to the December 1988 Form 10-K)	I
99(a)	-Kansas Gas and Electric Company's Annual Report on Form 10-K for the year ended December 31, 1993 (filed electronically)	
99(b)	-Report of K&A Energy Consultants, Inc. (filed as Exhibit 28 to the December 1988 Form 10-K)	I

WESTERN RESOURCES, INC.

Schedule V - Utility Plant

For the Year Ended December 31, 1993

Classification	Balance at Beginning of Period	Additions at Cost	Retire-ments	Transfers, Reclassi-fication	Balance at End of Period
	(Thousands of Dollars)				
Electric Plant:					
Steam Production.	$1,367,730	$ 52,064	$ 7,406	$ (7,154)	$1,405,234
Nuclear Production.	1,355,678	11,324	614	-	1,366,388
Internal Combustion Production.	34,273	1,374	445	-	35,202
Transmission.	499,775	7,082	1,296	27	505,588
Distribution.	809,617	43,216	4,859	(138)	847,836
General	111,666	15,211	2,658	13	124,232
Electric Plant Leased to Others	6,984	-	-	-	6,984
Construction Work in Progress .	49,068	10,230	-	-	59,298
Electric Plant Held for Future Use	25,290	5	129	7,109	32,275
Nuclear Fuel.	59,305	6,764	19,381	-	46,688
Plant Acquisition Adjustment. .	796,265	1,347	21	(12,089)	785,502
	5,115,651	148,617	36,809	(12,232)	5,215,227
Natural Gas Plant:					
Production and Gathering. . . .	9,704	24	23	5	9,710
Underground Storage	5,951	9,135	-	-	15,086
Transmission.	97,480	6,258	967	(26)	102,745
Distribution.	845,332	70,694	4,712	29	911,343
General	62,933	12,292	5,228	16	70,013
Gas Stored Underground.	2,969	-	-	-	2,969
Construction Work in Progress .	18,973	1,921	-	-	20,894
	1,043,342	100,324	10,930	24	1,132,760
Steam Heat Plant.	1,376	-	-	-	1,376
	$6,160,369	$ 248,941	$ 47,739	$ (12,208)	$6,349,363

WESTERN RESOURCES, INC.

Schedule V - Utility Plant

For the Year Ended December 31, 1992

Classification	Balance at Beginning of Period	Additions at Cost	Retire- ments	Transfers, Reclassi- fication	Acquisition of KG&E	Balance at End of Period
	(Thousands of Dollars)					
Electric Plant:						
Steam Production.	$ 892,082	$ 10,603	$ 2,987	$ -	$ 468,032	$1,367,730
Nuclear Production.	-	3,505	6,660	-	1,358,833	1,355,678
Internal Combustion Production.	34,168	106	1	-	-	34,273
Transmission.	276,889	9,997	935	(74)	213,898	499,775
Distribution.	416,027	38,636	4,343	74	359,223	809,617
General	46,075	5,578	976	(18)	61,007	111,666
Electric Plant Leased to Others	-	-	-	-	6,984	6,984
Construction Work in Progress .	7,697	25,630	-	(3)	15,744	49,068
Electric Plant Held for Future Use	9,832	-	-	-	15,458	25,290
Nuclear Fuel.	-	15,936	-	(87)	43,456	59,305
Plant Acquisition Adjustment. .	-	-	-		796,265	796,265
	1,682,770	109,991	15,902	(108)	3,338,900	5,115,651
Natural Gas Plant:						
Production and Gathering. . . .	9,711	18	12	(13)	-	9,704
Underground Storage	5,632	319	-	-	-	5,951
Transmission.	94,388	3,542	464	14	-	97,480
Distribution.	687,148	70,913	5,120	92,391 (1)	-	845,332
General	59,151	5,172	1,407	17	-	62,933
Gas Stored Underground.	2,969	-	-	-	-	2,969
Construction Work in Progress .	9,417	9,556	-	-	-	18,973
	868,416	89,520	7,003	92,409	-	1,043,342
Steam Heat Plant.	1,376	-	-	-	-	1,376
	$2,552,562	$199,511	$22,905	$92,301	$3,338,900	$6,160,369

(1) Includes $92,389,000 resulting from the adoption of Statement of Financial Accounting Standards No. 109 relating to the GSC acquisition adjustment.

WESTERN RESOURCES, INC.

Schedule V - Utility Plant

For the Year Ended December 31, 1991

Classification	Balance at Beginning of Period	Additions at Cost	Retire-ments	Transfers, Reclassi-fication	Balance at End of Period
	(Thousands of Dollars)				
Electric Plant:					
Steam Production.	$ 886,296	$ 9,135	$ 3,348	$ (1)	$ 892,082
Internal Combustion Production.	33,595	588	15	-	34,168
Transmission.	272,772	5,185	656	(412)	276,889
Distribution.	397,082	21,895	3,362	412	416,027
General	43,693	2,705	327	4	46,075
Construction Work in Progress .	4,721	2,976	-	-	7,697
Electric Plant Held for Future Use	9,832	-	-	-	9,832
	1,647,991	42,484	7,708	3	1,682,770
Natural Gas Plant:					
Production and Gathering. . . .	9,847	80	216	-	9,711
Underground Storage	5,566	5	(61)	-	5,632
Transmission.	93,222	1,643	350	(127)	94,388
Distribution.	618,856	69,725	8,862	7,429	687,148
General	46,455	15,223	2,792	265	59,151
Gas Stored Underground.	2,969	-	-	-	2,969
Construction Work in Progress .	15,481	(6,064)	-	-	9,417
	792,396	80,612	12,159	7,567	868,416
Steam Heat Plant.	1,376	-	-	-	1,376
	$2,441,763	$123,096	$19,867	$7,570	$2,552,562

WESTERN RESOURCES, INC.

Schedule VI - Accumulated Depreciation of Utility Plant

For the Year Ended December 31,

Description	Balance at Beginning of Period	Additions Charged to Costs and Expenses	Retire- ments	Other Charges(1)	Acquisition of KG&E	Balance at End of Period
			(Thousands of Dollars)			
1993						
Electric.	$1,387,907	$134,658	$39,012	$ 1,951	$ -	$1,485,504
Natural Gas	328,333	35,702	11,788	-	-	352,247
Steam Heat.	1,376	-	-	-	-	1,376
	$1,717,616	$170,360	$50,800	$ 1,951	$ -	$1,839,127
1992						
Electric.	$ 593,311	$112,631	$16,497	$ (162)	$698,624	$1,387,907
Natural Gas	231,431	32,918	6,315	70,299 (2)	-	328,333
Steam Heat.	1,376	-	-	-	-	1,376
	$ 826,118	$145,549	$22,812	$70,137	$698,624	$1,717,616
1991						
Electric.	$ 550,722	$ 53,384	$ 7,508	$(3,287)	$ -	$ 593,311
Natural Gas	209,481	35,912	11,477	(2,485)	-	231,431
Steam Heat.	1,376	-	-	-	-	1,376
	$ 761,579	$ 89,296	$18,985	$(5,772)	$ -	$ 826,118

(1) Removal costs of assets retired less salvage value.

(2) Includes $71,488,000 resulting from the adoption of Statement of Financial Accounting Standards No. 109 relating to the GSC acquisition adjustment.

SIGNATURE

Pursuant to the requirements of Sections 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

WESTERN RESOURCES, INC.

March 18, 1994

By JOHN E. HAYES, JR.
(John E. Hayes, Jr., Chairman of the Board,
President, and Chief Executive Officer)

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934 this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated:

Signature	Title	Date
JOHN E. HAYES, JR. (John E. Hayes, Jr.)	Chairman of the Board, President, and Chief Executive Officer (Principal Executive Officer)	March 18, 1994
S. L. KITCHEN (S. L. Kitchen)	Executive Vice President and Chief Financial Officer (Principal Financial and Accounting Officer)	March 18, 1994
FRANK J. BECKER (Frank J. Becker)		
GENE A. BUDIG (Gene A. Budig)		
C. Q. CHANDLER (C. Q. Chandler)		
THOMAS R. CLEVENGER (Thomas R. Clevenger)		
JOHN C. DICUS (John C. Dicus)	Directors	March 18, 1994
DAVID H. HUGHES (David H. Hughes)		
RUSSELL W. MEYER, JR. (Russell W. Meyer, Jr.)		
JOHN H. ROBINSON (John H. Robinson)		
MARJORIE I. SETTER (Marjorie I. Setter)		
LOUIS W. SMITH (Louis W. Smith)		
KENNETH J. WAGNON (Kenneth J. Wagnon)		

THE KANSAS POWER AND LIGHT COMPANY

Certificate of Designations
for a Series of Preference Stock
designated as "8.50% Preference Stock"

Pursuant to Section 17-6401(g) of the
General Corporation Code of the State of Kansas

The Kansas Power and Light Company, a corporation of the State of Kansas (hereinafter called the "Corporation"), by the President and Chief Executive Officer, KPL Division, an officer, authorized to exercise the duties ordinarily exercised by a Vice President, and an Assistant Secretary, DOES HEREBY CERTIFY as follows:

1. That pursuant to Article VI of the Restated Articles of Incorporation of the Corporation, as amended, the Corporation is authorized to issue 4,000,000 shares of Preference Stock, without par value, and the Board of Directors of the Corporation is expressly authorized to fix, to the extent permitted by law and said Article VI, the distinctive terms and characteristics of any and all series of Preference Stock.

2. That the Board of Directors of the Corporation, at a meeting duly convened and held on May 23, 1991, at which a quorum was present and acting throughout, duly and unanimously adopted the following resolutions authorizing the issuance of a series of the Corporation's Preference Stock, and fixing the designations, preferences and relative, participating, optional and other rights and qualifications, limitations and restrictions thereof other than those which would apply to all series of Preference Stock of the Corporation (for a statement of which reference is made to said Article VI) as follows:

> WHEREAS, the Board of Directors of The Kansas Power and Light Company (the "Company"), at a meeting duly called and held on January 23, 1991, authorized and empowered the proper officers of the Company to proceed to prepare for the sale by the Company, of such number of shares of the Company's authorized and unissued Preference Stock, without par value (the "Preference Stock"), in such amounts, up to $150,000,000 in value and at such time, including but not limited to a "shelf registration," as they deem appropriate and in the best interests of the Company;
>
> WHEREAS, pursuant to the authority delegated to the proper officers of the Company at the January 23 meeting, said officers have made arrangements with Dillon, Read & Co. Inc., as representative (the "Representative") of a syndicate of underwriters who are proposing to purchase 1,000,000 shares of Preference Stock pursuant to a firm commitment underwriting agreement substantially in the form previously distributed to each of the Directors;
>
> WHEREAS, the Company's Restated Articles of Incorporation, as amended, authorize the issuance in series of shares of the Preference Stock and fix the general terms and characteristics of such shares and authorize the Board of Directors of the Company to fix the distinctive terms and characteristics of any and all series of the Preference Stock in a manner not inconsistent with, and within the prescribed limits of, the Restated Articles of Incorporation, as amended; and
>
> NOW, THEREFORE, BE IT RESOLVED, that a new series of the Preference Stock, without par value, of the Company be, and it hereby is, established;
>
> FURTHER RESOLVED, that the following be, and it hereby is, a statement of the designation and the powers, preferences and rights, and the qualifications, limitations and restrictions, of such series, subject to the provisions set forth in the Restated Articles of Incorporation, as amended (the "Articles"):
>
> 1. Designation. The Preference Stock created and authorized hereby shall be designated as the "8.50% Preference Stock" (the "8.50% Series"). The number of shares constituting the 8.50% Series shall be 1,000,000

and no more.

2. Dividends. The rate per annum of dividends on the 8.50% Series shall be $8.50 per share and dividends thereon shall be cumulative from and including the date of original issue on all shares issued before July 1, 1991, which date shall be the first dividend payment date for said shares, and payable thereafter on the first day of January, April, July and October of each year. For any period during which any share of such series is outstanding less or more than a full quarterly dividend period, the dividends payable shall be computed on the basis of twelve 30-day months and the actual number of days elapsed in the period for which the dividends are payable.

3. Optional Redemption. Subject to the provisions of paragraph 4 hereof, the shares of the 8.50% Series shall be redeemable in whole or in part at the option of the Company, subject to the terms, provisions and effect as generally provided for redemption of shares of the Company's Preference Stock in the Articles, at a price of $108.50 per share if such date is prior to July 1, 1992 and at the following applicable prices per share during the respective 12-month periods beginning on July 1 of the years indicated:

12-Month Period Beginning July 1	Redemption Price Per Share	12-Month Period Beginning July 1	Redemption Price Per Share
1993	$107.37	1998	$104.53
1994	$106.80	1999	$103.97
1995	$106.23	2000	$103.40
1996	$105.67	2001	$102.83
1997	$105.10		

and at $100 per share if redeemed on July 1, 2006 or thereafter, plus, in each case, an amount equal to the accrued but unpaid dividends on said shares to the date of redemption; provided, however, that no shares of the 8.50% Series may be redeemed (otherwise than by sinking fund redemption provided for in paragraph 4 hereof) prior to July 1, 1996 if such redemption is for the purpose of or in anticipation of refunding such shares through the use, directly or indirectly, of funds borrowed by the Company, or through the use, directly or indirectly, of funds derived through the issuance by the Company of stock ranking prior to or on a parity with the 8.50% Series as to dividends or assets, if such borrowed funds have an effective interest cost to the Company (computed in accordance with generally accepted financial practice and before deduction of commissions and expenses) or such stock has an effective dividend cost to the Company (so computed) of less than 8.50% per annum.

In the case of an optional redemption of less than all of the shares of the 8.50% Series at the time outstanding, the Company shall select by lot the shares so to be redeemed.

4. Sinking Fund Redemption. Notwithstanding the provisions of paragraph 3 hereof, the shares of the 8.50% Series shall be subject to redemption as and for a sinking fund as follows:

On July 1, 1997 and on each July 1, thereafter (each such date being hereinafter referred to as an "8.50% Series Sinking Fund Redemption Date") for so long as any shares of the 8.50% Series shall remain outstanding, the Company shall redeem, out of funds legally available therefor and otherwise in the manner hereinafter provided, 50,000 shares of the 8.50% Series (or the number of shares then outstanding if less than 50,000) at the sinking fund redemption price of $100.00 per share, plus, as to each share so redeemed, an amount equal to the accrued dividends thereon to the date of redemption (the obligation of the Company so to redeem the shares of the 8.50% Series being hereinafter referred to as the "8.50% Series Sinking Fund Obligation"). The 8.50% Series Sinking Fund Obligation shall be cumulative. If on any 8.505 Series Sinking Fund Redemption Date, the Company shall be prevented from redeeming the full number of shares required to be redeemed on the date, the 8.50% Series Sinking Fund Obligation with respect to the shares not redeemed shall carry forward and funds legally available for redemption as aforesaid shall be applied to such 8.50% Series Sinking Fund Obligation to each succeeding Sinking Fund Redemption Date on which the Company shall not be prevented from effecting such redemption until all such shares have been redeemed. In addition to the 8.50% Series Sinking Fund Obligation, the Company shall have the option, which shall be noncumulative, to redeem, upon authorization of the Board of Directors of the Company and otherwise in the manner hereinafter provided, on each 8.50% Series Sinking Fund Redemption Date, at the sinking fund redemption price of $100.00 per share, plus, as to each share so redeemed, an amount equal to the accrued dividends thereon to the date of redemption, up to 50,000 additional shares of the 8.50% Series. The shares of the 8.50% Series which are to be the subject of mandatory or optional sinking fund redemption shall be selected by the Company by lot.

Notice of each sinking fund redemption shall be given, and deposit of the aggregate sinking fund redemption price may be made, subject to the terms, provisions and effect as provided generally for redemption of shares of the Company's Preference Stock in the Articles. The Company shall be entitled, at its election, to credit against its 8.50% Series Sinking Fund Obligation any shares of the 8.50% Series redeemed (other than shares of the 8.50% Series redeemed pursuant to the 8.50% Series Sinking Fund Obligation or optionally redeemed pursuant to this paragraph 4), purchased or otherwise acquired and not previously credited against the 8.50% Series Sinking Fund Obligation.

5. Voluntary Liquidation, Dissolution or Winding Up. In the event of the voluntary liquidation, dissolution or winding up of the Company, the holders of the 8.50% Series shall be entitled to receive (on a pro rata basis with holders of any other series of Preference Stock, from any assets and funds of the Company remaining after payment of the debts and other liabilities of the Company and after payment to the holders of Preferred Stock of the preferential amount or amounts to which such holders are entitled thereon) for each share an amount equal to the then current redemption price per share provided for under "Optional Redemption" in paragraph 3 hereof plus, as to each share, an amount equal to the accrued dividends thereon to the date of distribution.

6. Involuntary Liquidation, Dissolution or Winding Up. In the event of the involuntary liquidation, dissolution or winding up of the Company, the holders of the 8.50% Series shall be entitled to receive (on a pro rata basis with holders of any other series of Preference Stock, from any assets and funds of the Company remaining after payment of the debts and other liabilities of the Company and after payment to the holders of Preferred Stock of the preferential amount or amounts to which such holders are entitled thereon) $100 for each share, which amount shall be deemed to be the involuntary liquidation price per share for the 8.50% Series, plus, as to each share, an amount equal to the accrued dividends thereon to the date of distribution.

7. Conversion Privileges. Shares of the 8.50% Series shall not be convertible into any class, or series of any class of, capital stock of the Company.

8. Negative Covenant. The Company hereby covenants and agrees that, so long as any shares of the 8.50% Series are outstanding, it will not issue any additional shares of preferred stock or any stock convertible into such preferred stock.

IN WITNESS WHEREOF, The Kansas Power and Light Company has made this Certificate under its seal and the hand of the President and Chief Executive Officer, KPL Division, an officer authorized to exercise the duties ordinarily exercised by a Vice President, and an Assistant Secretary, this 31st day of March, 1991.

THE KANSAS POWER AND LIGHT COMPANY

By /s/ William E. Brown
William E. Brown
President and Chief Executive
Officer, KPL Division

ATTEST:

/s/ Stacy F. Kramer
Stacy F. Kramer
Assistant Secretary

STATE OF KANSAS)
) ss:
COUNTY OF SHAWNEE)

BE IT REMEMBERED, that on this 31st day of March, 1991, before me, the undersigned, a Notary Public in and for the County and State aforesaid, personally came William E. Brown, President and Chief Executive Officer, KPL Division of The Kansas Power and Light Company, a corporation duly organized, incorporated and existing under the laws of the State of Kansas, who is personally known to me to be such officer, and who is personally known to me to be the same person who executed as such officer the above instrument in writing, and he duly acknowledge execution of the same as Vice President of said corporation.

IN WITNESS WHEREOF, I have hereunto subscribed my name and affixed my official seal the day and year last above written.

Notary Public

My Commission expires:

THE KANSAS POWER AND LIGHT COMPANY

Certificate of Designations
for a Series of Preference Stock
designated as "7.58% Preference Stock"

Pursuant to Section 17-6401(g) of the
General Corporation Code of the State of Kansas

The Kansas Power and Light Company, a corporation of the State of Kansas (hereinafter called the "Corporation"), by James S. Haines, Jr., Executive Vice President and Chief Administrative Officer, authorized to exercise the duties ordinarily exercised by a Vice President, and an Assistant Secretary, DOES HEREBY CERTIFY as follows:

1. That pursuant to Article VI of the Restated Articles of Incorporation of the Corporation, as amended, the Corporation is authorized to issue 4,000,000 shares of Preference Stock, without par value, and the Board of Directors of the Corporation is expressly authorized to fix, to the extent permitted by law and said Article VI, the distinctive terms and characteristics of any and all series of Preference Stock.

2. That the Board of Directors of the Corporation, at a meeting duly convened and held on February 25, 1992, at which a quorum was present and acting throughout, duly and unanimously adopted the following resolutions authorizing the issuance of a series of the Corporation's Preference Stock, and fixing the designations, preferences and relative, participating, optional and other rights and qualifications, limitations and restrictions thereof other than those which would apply to all series of Preference Stock of the Corporation (for a statement of which reference is made to said Article VI) as follows:

WHEREAS, the Board of Directors of The Kansas Power and Light Company, at a meeting duly called and held on January 23, 1991, authorized and empowered the proper officers of the Company to proceed to prepare for the sale by the Company, of such number of shares of the Company's authorized and unissued Preference Stock, without par value (the "Preference Stock"), in such amounts, up to $150,000,000 in value and at such time, including but not limited to a "shelf registration," as they deem appropriate and in the best interest of the Company;

WHEREAS, on May 17, 1991 the Company filed a registration statement on Form S-3, File No. 33-40527 (the "Registration Statement") with the Securities and Exchange Commission ("SEC") to register for the shelf 1,500,000 shares of Preference Stock, which Registration Statement was declared effective on May 23, 1991;

WHEREAS, a Prospectus Supplement was filed with the SEC on May 31, 1991 with respect to the public offering of 1,000,000 shares of Preference Stock designated as the "8.50% Preference Stock" (the "8.50% Series") at $100 per share, the Underwriting Agreement with respect to the purchase of such shares by the Underwriters at a discount of $0.875 per share was signed by the Company and the Underwriters on that date and the closing for the purchase and sale pursuant thereto was held on June 10, 1991;

WHEREAS, pursuant to the authority delegated to the proper officers of the Company at the January 23, 1991 and February 25, 1992 meetings, said officers have made arrangements with Dillon, Read & Co. Inc., as representative (the "Representative") of a syndicate of underwriters who are proposing to purchase the remaining 500,000 shares of Preference Stock covered by the Registration Statement pursuant to a firm commitment underwriting agreement substantially in the form executed with respect to the 8.50% Series;

WHEREAS, the Company's Restated Articles of Incorporation, as amended, authorize the issuance in series of shares of the Preference Stock and fix the general terms and characteristics of such shares and authorize the Board of Directors of the Company to fix the distinctive terms and characteristics of any and all series of the Preference Stock in a manner not inconsistent with, and within the prescribed limits of, the Restated Articles of Incorporation, as amended; and

NOW, THEREFORE, BE IT RESOLVED, that the Board of Directors deems it desirable and in the best interests of the Company to create a new series of Preference Stock, without par value, consisting of the 500,000 additional shares of Preference Stock covered by the Registration Statement and that such new series be publicly offered and sold and issued by the Company;

FURTHER RESOLVED, that the following be, and it hereby is, a statement of the designation and the powers, preferences and rights, and the qualifications, limitations and restrictions, of such series, subject to the provisions set forth in the Restated Articles of Incorporation, as amended (the "Articles"):

1. Designation. The Preference Stock created and authorized hereby shall be designated as the "7.58% Preference Stock" (the "7.58% Series"). The number of shares constituting the 7.58% Series shall be 500,000 and no more.

2. Dividends. The rate per annum of dividends on the 7.58% Series shall be $7.58 per share and dividends thereon shall be cumulative from and including the date of original issue on all shares issued before July 1, 1992, which date shall be the first dividend payment date for said shares, and payable thereafter on the first day of January, April, July and October of each year. For any period during which any share of such series is outstanding less or more than a full quarterly dividend period, the dividends payable shall be computed on the basis of twelve 30-day months and the actual number of days elapsed in the period for which the dividends are payable.

3. Optional Redemption. Subject to the provisions of paragraph 4 hereof, the shares of the 7.58% Series shall be redeemable in whole or in part at the option of the Company, subject to the terms, provisions and effect as generally provided for redemption of shares of the Company's Preference Stock in the Articles, at a price of $107.58 per share if such date is prior to April 1, 1993 and at the following applicable prices per share during the respective 12-month periods beginning on April 1 of the years indicated:

12-Month Period Beginning April 1	Redemption Price Per Share	12-MonthPeriod Beginning April 1	Redemption Price Per Share
1993	$106.82	1998	$103.03
1994	$106.06	1999	$102.27
1995	$105.31	2000	$101.52
1996	$104.55	2001	$100.76
1997	$103.79		

and at $100 per share if redeemed on April 1, 2002 or thereafter, plus, in each case, an amount equal to the accrued but unpaid dividends on said shares to the date of redemption; provided, however, that no shares of the 7.58% Series may be redeemed (otherwise than by sinking fund redemption provided for in paragraph 4 hereof) prior to April 1, 1997 if such redemption is for the purpose of or in anticipation of refunding such shares through the use, directly or indirectly, of funds borrowed by the Company, or through the use, directly or indirectly, of funds derived through the issuance by the Company of stock ranking prior to or on a parity with the 7.58% Series as to dividends or assets, if such borrowed funds have an effective interest cost to the Company (computed in accordance with generally accepted financial practice and before deduction of commissions and expenses) or such stock has an effective dividend cost to the Company (so computed) of less than 7.58% per annum.

In the case of an optional redemption of less than all of the shares of the 7.58% Series at the time outstanding, the Company shall select by lot the shares so to be redeemed.

4. Sinking Fund Redemption. Notwithstanding the provisions of paragraph 3 hereof, the shares of the 7.58% Series shall be subject to redemption as and for a sinking fund as follows:

The Company shall redeem, out of funds legally available therefor and otherwise in the manner hereinafter provided, (i) 25,000 shares of the 7.58% Series (or the number of shares then outstanding if less than 25,000) on each April 1 of the, years 2002, 2003, 2004, 2005 and 2006, and (ii) 375,000 shares of the 7.58% Series (or the number of shares then outstanding if less than 375,000) on April 1, 2007 (each of the dates referred to (i) and (ii) above being referred to as an "7.58% Series Sinking Fund Redemption Date"), in each case at the sinking fund redemption price of $100.00 per share, plus, as to each share so redeemed, an amount equal to the accrued dividends thereon to the date of redemption (the obligation of the Company so to redeem the shares of the 7.58% Series being hereinafter referred to as the "7.58% Series Sinking Fund Obligation"). The 7.58% Series Sinking Fund Obligation shall be cumulative. If on any 7.58% Series Sinking Fund Redemption Date, the Company shall be prevented from redeeming the full number of shares required to be redeemed on that date, the 7.58% Series Sinking Fund Obligation with respect to the shares not redeemed shall carry forward and funds legally available for redemption as aforesaid shall be applied to such 7.58% Series Sinking Fund Obligation on each succeeding Sinking Fund Redemption Date on which the Company shall not be prevented from effecting such redemption until all such shares shall have been redeemed. In addition to the 7.58% Series Sinking Fund Obligation, the Company shall have the option, which shall be noncumulative, to redeem, upon authorization of the Board of Directors of the Company and otherwise in the manner hereinafter provided, on each 7.58% Series Sinking Fund Redemption Date, at the sinking fund redemption price of $100.00 per share, plus, as to each share so redeemed, an amount equal to the accrued dividends thereon to the date of redemption, up to 25,000 additional shares of the 7.58% Series. The shares of the 7.58% Series which are to be the subject of mandatory or optional sinking fund redemption shall be selected by the Company by lot.

Notice of each sinking fund redemption shall be given, and deposit of the aggregate sinking fund redemption price may be made, subject to the terms, provisions and effect as provided generally for redemption of shares of the Company's Preference Stock in the Articles. The Company shall be entitled, at its election, to credit against its 7.58% Series Sinking Fund Obligation any shares of the 7.58% Series redeemed (other than shares of the 7.58% Series redeemed pursuant to the 7.58% Series Sinking Fund Obligation or optionally redeemed pursuant to this paragraph 4), purchased or otherwise acquired and not previously credited against the 7.58% Series Sinking Fund Obligation.

5. Voluntary Liquidation, Dissolution or Winding Up. In the event of the voluntary liquidation, dissolution or winding up of the Company, the holders of the 7.58% Series shall be entitled to receive (on a pro rata basis with holders of any other series of Preference Stock, from any assets and funds of the Company remaining after payment of the debts and other liabilities of the Company and after payment to the holders of Preferred Stock of the preferential amount or amounts to which such holders are entitled thereon) for each share an amount equal to the then current redemption price per share provided for under "Optional Redemption" in paragraph 3 hereof plus, as to each share, an amount equal to the accrued dividends thereon to the date of distribution.

6. Involuntary Liquidation, Dissolution or Winding Up. In the event of the involuntary liquidation, dissolution or winding up of the Company, the holders of the 7.58% Series shall be entitled to receive (on a pro rata basis with holders of any other series of Preference Stock, from any assets and funds of the Company remaining after payment of the debts and other liabilities of the Company and after payment to the holders of Preferred Stock of the preferential amount or amounts to which such holders are entitled thereon) $100 for each share, which amount shall be deemed to be the involuntary liquidation price per share for the 7.58% Series, plus, as to each share, an amount equal to the accrued dividends thereon to the date of distribution.

7. Conversion Privileges. Shares of the 7.58% Series shall not be convertible into any class, or series of any class of, capital stock of the Company.

8. Negative Covenant. The Company hereby covenants and agrees that, so long as any shares of the 7.58% Series are outstanding, it will not issue any additional shares of preferred stock or any stock convertible into such preferred stock.

IN WITNESS WHEREOF, The Kansas Power and Light Company has made this Certificate under its seal and the hand of James S. Haines, Jr., Executive Vice President and Chief Administrative officer, authorized to exercise the duties ordinarily exercised by a Vice President, and an Assistant Secretary, this 8th day of April, 1992.

THE KANSAS POWER AND LIGHT COMPANY

By /s/ James S. Haines, Jr.
James S. Haines, Jr.
Executive Vice President and
Chief Administrative Officer

ATTEST:

/s/ Stacy F. Kramer
Stacy F. Kramer
Assistant Secretary

STATE OF KANSAS)
) ss:
COUNTY OF SHAWNEE)

BE IT REMEMBERED that on this 8th day of April, 1992, before me, the undersigned, a Notary Public in and for the County and State aforesaid, personally came James S. Haines, Jr., Executive Vice President and Chief Administrative Officer, of The Kansas Power and Light Company, a corporation duly organized, incorporated and existing under the laws of the State of Kansas, who is personally known to me to be such officer, and who is personally known to me to be the same person who executed as such officer the above instrument in writing, and he duly acknowledge execution of the same as Executive Vice President of said corporation.

IN WITNESS WHEREOF, I have hereunto subscribed my name and affixed my official seal the day and year last above written.

Notary Public

My Commission expires:

1993
AMENDED AND RESTATED
COAL SUPPLY AGREEMENT

This 1993 Amended and Restated Coal Supply Agreement is made and entered into this 31st day of March, 1993, by and among Amax Coal West, Inc., a Delaware corporation ("Seller"), and Western Resources, Inc., a Kansas corporation (WRI); Kansas Gas and Electric Company, a Kansas corporation; Missouri Public Service, a division of UtiliCorp United Inc., a Delaware corporation; and WestPlains Energy, a division of UtiliCorp United Inc., a Delaware corporation, (collectively referred to herein as "Buyers")

WITNESSETH:

WHEREAS, Buyers are public utilities that render electric utility service to certain areas within the States of Kansas, Missouri, and Colorado; and

WHEREAS, Seller and WRI (formerly known as The Kansas Power and Light Company) entered into a Coal Supply Agreement for the sale and purchase of coal dated July 1, 1973, as such has been amended from time to time; and

WHEREAS, Buyers desire to secure a supply of coal in the quantity and of the quality hereinafter specified, suitable for use in Units 1, 2, and 3, and, upon construction and commencement of operation, in unit 4 of the Jeffrey Energy Center situated in Pottawatomie County, Kansas (the "Energy Center") and deliveries thereof for said Units as hereinafter set forth; and

WHEREAS, Seller has represented to Buyers that it is experienced in the commercial production of coal and that it now owns, has leased or controls by location (as such phrase is commonly used in the coal industry) certain coal reserves that are assigned to its present surface mining operation located near Gillette, Wyoming and known as the Eagle Butte Mine (hereinafter referred to as the "Mine") as shown on Exhibit A attached hereto and hereby made a part hereof and that said reserves of coal have the quantity, quality and characteristics hereinafter specified; and

WHEREAS, Seller desires to mine coal from the Mine and sell the same to Buyers for utilization in the Energy Center, and Buyers desire to buy such coal from Seller; and

WHEREAS, the parties hereto desire to set forth their mutual understandings and covenants with regard to the aforesaid coal supply arrangements.

NOW, THEREFORE, in consideration of the premises and of the mutual covenants and undertakings of the parties herein contained, Seller agrees to sell and deliver to Buyers, and Buyers agree to buy and accept delivery of coal from Seller subject to the following terms, conditions and provisions:

Section 1. Definitions.

For purposes of this Agreement:

(a) "Additional Charge" shall apply only to Coal requested by Buyers pursuant to Section 5(b) hereof and shall be an amount equal to $0.0150 per MMBtu effective January 1, 1993, as adjusted pursuant to Section 8(d) hereof.

(b) "Adjustment Quarter" is defined in regard to adjustments and calculations made hereunder as the Quarter for which such adjustments or calculations are being made.

(c) "Agent/Operator" is defined as Western Resources, Inc., a Kansas corporation, formerly known as The Kansas Power and Light Company, which is the operator of the Energy Center for Buyers and shall serve as agent for Buyers under this Agreement.

(d) "Agreement" is defined as this 1993 Amended and Restated Coal Supply Agreement.

(e) "Alternate Source Coal" shall have the meaning ascribed to it in Section 5(c) hereof.

(f) "Alternate Source Mine" shall have the meaning ascribed to it in Section 5(c) hereof.

(g) "Amax Land Royalties" is defined as all Royalties except those Royalties set out in section l(rr)(i) hereof.

(h) "Annual Base Quantity" is defined as the minimum number of Btu's to be sold, purchased and delivered under this Agreement for each Contract Year during the Term pursuant to the provisions of Section 3(b) hereof.

(i) "as received basis" shall have the meaning ascribed to it in ASTM Standard D-3180.

(j) "ASTM" means the American Society for Testing and Materials.

(k) "Basic Source Coal" means coal shipped from the Mine or Belle Ayr Mine.

(l) "Btu's" are defined as British thermal units.

(m) "Business Day" means any calendar day other than a Saturday, Sunday or legal holiday recognized and observed by the Federal Government.

(n) "Buyers" shall have the meaning ascribed to it in the preamble hereof.

(o) "Coal" means coal to be delivered by Seller and purchased by Buyers pursuant hereto.

(p) "Competitive Offer" shall have the meaning ascribed to it in Section 3(c) hereof.

(q) "Consultant" shall mean an employee or person otherwise affiliated with one of the entities listed in Exhibit K, attached hereto and hereby made a part hereof, as the same may be amended from time to time.

(r) "Contract Year" means a calendar year.

(s) "Current Index" is defined:

(i) for published indices determined on a monthly basis, as the arithmetic mean of the available monthly index values for the second and third Quarters preceding an Adjustment Quarter; provided, if less than three monthly index values are available for any such two-Quarter period, then the provisions of Section 8(e) hereof shall apply; and

(ii) for published indices determined on a Quarterly basis, as the arithmetic mean of the available Quarterly index values for the second and third Quarters preceding an Adjustment Quarter; provided, if less than two Quarterly index values are available for any such two-Quarter period, then the provisions of Section 8(e) hereof shall apply.

(t) "Deficient Quantity" is defined as the difference, but not less than zero, obtained by subtracting the total quantity of Btu's purchased under this Agreement in a Contract Year from the Annual Base Quantity (less any adjustments allowed pursuant to the terms of this Agreement) Buyers are required to purchase during such Contract Year pursuant to Section 3(b) hereof.

(u) "Deficient Quantity Charge" shall be an amount equal to $0.3163/MMBtu effective for Contract Year 1993, and shall thereafter be calculated pursuant to Section 4(a) hereof.

(v) "Dispute" shall have the meaning ascribed to it in Section 16 hereof.

(w) "Energy Center" shall have the meaning ascribed to it in the preamble hereof.

(x) "Force Majeure" shall have the meaning ascribed to it in Section 13 hereof.

(y) "IC" (Indexed Component) is defined as that component of the Price which shall be adjusted pursuant to Section 8(a)(ii) or Section 8(c) hereof.

(z) "ICIP" (Indexed Component of Incremental Price) is defined as that component of the Incremental Price which shall be adjusted pursuant to Section 8(b)(ii) or Section 8(c), or redetermined pursuant to Section 8(b)(iii) hereof.

(aa) "Incremental Price" (IP) is defined as the dollars per MMBtu to be paid by Buyers to Seller pursuant to Section 7 hereof, as adjusted pursuant to Section 8(b) or Section 8(c), or redetermined pursuant to Section 8(b)(iii) hereof, for all Incremental Quantity Coal, except for Off-Specification Coal which shall be priced pursuant to Section 6(b) hereof.

(bb) "Incremental Quantity Coal" is defined as all quantity of Coal delivered hereunder during any Contract Year in excess of the Annual Base Quantity for that Contract Year.

(cc) "Invoiced Items" shall have the meaning ascribed to it in Section 12(d) hereof.

(dd) "Market Price" shall mean those determinations made by Consultants pursuant to Section 8(b)(iii) hereof.

(ee) "Mine" shall have the meaning ascribed to it in the preamble hereof.

(ff) "MMBtu" is defined as one million Btu's.

(gg) "Monthly Base Quantity" shall have the meaning ascribed to it in Section 9(b) hereof.

(hh) "New Law" is defined as the enactment, repeal or amendment of any federal, state or local law, ordinance, regulation or rule or any judicial, legislative or executive change in the wording, interpretation or enforcement of any federal, state or local law, ordinance, regulation or rule or any mandate, guideline or policy issued pursuant thereto, which affects Seller's cost of mining, producing, processing, hauling or loading Coal at the Mine after December 31, 1992.

(ii) "Off-Specification Coal" is defined as Coal delivered hereunder which (on an "as received basis") on a monthly weighted average basis, when sampled and analyzed pursuant to Section 11 hereof, has any one of the following specifications:

Coal Characteristics	Off-Specifications
Moisture - exceeding	32.1%
Ash - exceeding	7.0 lbs./MMBtu
Volatile Matter - less than	27.8%
Fixed Carbon - less than	26.3%
Sulfur - exceeding	0.55 lbs./MMBtu
Calorific Value - less than	8150 Btu's/lb.
Ash Fusion (Reducing Atmosphere)	
Initial Deformation - less than	2020 degrees F
Softening (H=W) less than	2055 degrees F
Softening (H=1/2W) less than	2120 degrees F
Fluid - less than	2130 degrees F

Grindability (Hardgrove Index)-less than 52 (at 20% moisture)

(jj) "Other Producer" shall have the meaning ascribed to it in Section 3(c)(i) hereof.

(kk) "Price" is defined as the dollars per MMBtu to be paid by Buyers to Seller pursuant to Section 7 hereof, as calculated pursuant to Section 8(a) and Section 8(c) hereof, for all Annual Base Quantity Coal delivered and accepted hereunder, except for Off-Specification Coal which shall be priced pursuant to Section 6(b) hereof.

(ll) "Prior Index" is defined:

(i) for the April 1, 1993, Adjustment Quarter:

(A) for published indices determined on a monthly basis, as the arithmetic mean of the available monthly index values for the second and third Quarters of 1992; provided, if less than three monthly index values are available for this two-Quarter period, then the provisions of Section 8(e) hereof shall apply; and

(B) for published indices determined on a Quarterly basis, as the arithmetic mean of the available Quarterly index values for the second and third Quarters of 1992; provided, if less than two Quarterly index values are available for this two-Quarter period, then the provisions of Section 8(e) hereof shall apply; and

(ii) after the April 1, 1993, Adjustment Quarter, as the Current Index from the previous Adjustment Quarter.

(mm) "Quarter" is defined as the three-month period of time beginning Quarterly.

(nn) "Quarterly" is defined as occurring each January 1, April 1, July 1 and October 1.

(oo) "Quarterly Adjustment Ratio" is defined as the sum of the weighted changes of the item indices, described in Columns (I) and (II) of the PRICE ADJUSTMENT INDEX SOURCES AND WEIGHTS TABLE below, calculated as follows:

For each item index divide the Current Index by the Prior Index and multiply the result by the fixed percentage weight (changed to a decimal) listed under Column (III) of the PRICE ADJUSTMENT INDEX SOURCES AND WEIGHTS TABLE below. The result of such multiplication for each item index shall then be added to obtain the sum of the weighted changes.

The value for each index shall be the value as first published in the respective publication listed in the PRICE ADJUSTMENT INDEX SOURCES AND WEIGHTS TABLE below. All calculations to determine the weighted change for each index shall be rounded to four decimal places. The Quarterly Adjustment Ratio shall be calculated to four decimal places. An example of these calculations is shown on Exhibit D attached hereto and hereby made a part hereof.

PRICE ADJUSTMENT INDEX SOURCES AND WEIGHTS TABLE

ITEM (I)	SOURCE (II)	WEIGHT (III)
1. Labor		
a. Average hourly earnings per worker, not seasonally adjusted, Private nonfarm payrolls, Mining	(1)	10.0%
b. Average hourly earnings, Wyoming, not seasonally adjusted	(2)	10.0%
2. Materials & Supplies		
a. Industrial Commodities	(3)	10.0%
b. Intermediate materials, supplies and components	(4)	15.0%
c. Mining machinery parts, excluding drills Commodity Code 1192-5301	(3)	10.0%
3. Other		
a. Gross private domestic investment, Fixed investments, Nonresidential, Implicit price deflator	(5)	20.0%
b. Gross domestic product, Business, Nonfarm less housing	(6)	5.0%
c. Bituminous coal, Spot sales of prepared bituminous coal, Steam electric utilities Commodity Code 0512-0209	(3)	20.0%
4. Total		100%

(1) Listed under the "Hourly and Weekly Earnings" subsection of "5. Labor Force, Employment and Earnings: of "Current Business Statistics" section of Survey of Current Business published monthly by the Bureau of Economic Analysis of the U. S. Department of Commerce.

(2) Listed under Table C-8 "Average houses and earnings of production workers on manufacturing payrolls in States and selected areas," of Employment and Earnings, published monthly by the Bureau of Labor Statistics, U.S. Department of Labor.

(3) Listed under Table 6 "Producer price indexes and percent changes for commodity groupings and individual items, "of Producer Price Indexes published monthly by the Bureau of Labor Statistics, U.S. Department of Labor.

(4) Listed under Table 1 "Producer price indexes and percent changes by state of processing," of Producer Price Indexes, published monthly by the Bureau of Labor Statistics, U. S. Department of Labor.

(5) Listed under THE NATIONAL INCOME AND PRODUCT ACCOUNTS, selected NIPA Tables, Table 7.1 "Fixed-Weighted and Alternative Quantity and Price Indexes for Gross Domestic Product" of Survey of Current Business, published monthly by the Bureau of Economic Analysis of the U. S. Department of Commerce.

(6) Listed under THE NATIONAL INCOME AND PRODUCT ACCOUNTS, Selected NIPA Tables, Table 7.14 "Implicit Price Deflators for Gross Domestic Product by Section," of Survey of Current Business, published monthly by the Bureau of Economic Analysis of the U. S. Department of Commerce.

(pp) "Reclamation Fee is defined as costs incurred by Seller for Abandoned Mine Land Fees as presently set forth in Part 870 of Title 30, Code of Federal Regulations (1992) and such statutes, rules and regulations as shall be subsequently applicable.

(qq) "Royalty" or "Royalties" is defined as an amount payable by Seller to a third party for the right or privilege to engage in coal mining activities at the Mine.

(rr) "RTRC" (Royalties and Tax Related Component) is defined as that component of the Price which shall be calculated pursuant to Section 8(a)(i) hereof and is attributable to:

(i) Royalties payable to the following third parties and their successors in interest for Coal produced at the Mine:

(A) the United States Department of the Interior as set forth in Federal Coal Leases, W-0313773 and W-78631, and any other coal leases entered into with the United States Department of the Interior subsequent to December 31, 1992, with respect to coal reserves located adjacent to or near the Mine,
coal reserves located adjacent to or near the Mine,

(B) the State of Wyoming as set forth in Wyoming State Coal Lease, 0-27078, and any other coal leases entered into with the State of Wyoming subsequent to December 31, 1992, with respect to coal reserves located adjacent to or near the Mine, and

(C) John Organ as set forth in a Letter of Proposed Settlement dated January 18, 1969 between Ayrshire Collieries corporation and John E. Organ and Eunice Organ.

(ii) costs incurred by Seller at the Mine for;

(A) Wyoming severance taxes as presently set forth in Wyoming Statues Title 39, the Wyoming Constitution Article XV and Regulations of the Wyoming Department of Revenue and notices thereunder (1992) and such constitutions, statutes and regulations as shall be subsequently applicable; and
(B) Campbell County, Wyoming ad valorem taxes on production as set forth in Article XV Section 3 of the Constitution of the State of Wyoming;

(iii) costs incurred by Seller at the Mine for Federal Black Lung Excise Tax as presently set forth in Section 48.4121-1, Subpart H of Part 48 of Title 26, Code of Federal Regulations (1992) and such statutes, rules and regulations as shall be subsequently applicable;

(iv) changes in the Federal Statutory Depletion rate from the base rate of 10 percent as set forth in Section 613 (b) (4) of Title 26, United States Code (1984); and (v) costs incurred by Seller for a New Law which are to be included in the RTRC pursuant to the procedures set forth in Section 8(c) hereof.

(ss) "RTRCIP" (Royalties and Tax Related Component of Incremental Price) is defined as the RTRC component of the Incremental Price which shall be calculated pursuant to Section 8(b)(i) hereof and is attributable to those items set forth in Section l(rr)(i) through (v) hereof.

(tt) "Seller" shall have the meaning ascribed to it in the preamble hereof.

(uu) "Seller's Law Costs" is defined as all changes in Seller's cost of mining, producing, processing, hauling or delivering Coal at the Mine caused by a New Law.

(vv) "Seller's Scales" means a batch load weighing system or track scales located at the Mine, Belle Ayr Mine or an Alternate Source Mine capable of weighing the Coal to be delivered hereunder.

(ww) "Survey Period" is defined as the four Quarters subsequent to the date that a New Law first affects Seller's Law Costs.

(xx) "Term" shall have the meaning ascribed to it in Section 2 hereof.

(yy) "Termination Charge" shall have the meaning ascribed to it in Section 15(a) hereof.

(zz) "Utilization Cost" shall mean the net additional cost per MMBtu reasonably expected to be incurred by Buyers with respect to the handling and utilization of Alternate Source Coal.

Whenever used in this Agreement, the terms "cost," "costs," "paid," "payments," and "expenses" shall include all such items whether actually paid by Seller or accrued on Seller's books and records in accordance with generally accepted accounting principles and procedures.

Section 2. Term of Agreement.

(a) Term. The term of this Agreement shall be for a period commencing on January 1, 1993, and ending on December 31, 2020 (the "Term").

(b) Extension of Term. If Buyers wish to extend the Term for an additional period of up to five years for the purposes of purchasing additional coal hereunder, they shall notify Seller at least 36 months prior to the expiration of the Term. If, within 30 days after receipt of such notice, Seller determines, in its sole judgment, that it will have coal available for sale after the expiration of the Term, it shall notify Buyers of the quantity of coal which will be available. Buyers and Seller shall, within 60 days after Buyers' receipt of such notice, meet in order to arrive at mutually acceptable terms and conditions to cover the sale of such coal. If no mutually acceptable terms and conditions are reached, this Agreement shall not be extended beyond December 31, 2020.

Section 3. Quantities of Coal.

(a) Requirements Contract. This is a requirements contract pursuant to which Buyers shall purchase exclusively from Seller under the terms of this Agreement all coal, except as provided in Sections 6, 13 and 15 hereof, necessary to operate Units 1 - 3 of the Energy Center through December 31, 2020. If Buyers construct and commence operations of Unit 4 of the Energy Center and the Unit utilizes coal then Buyers shall purchase exclusively from Seller all coal to operate that Unit through December 31, 2013. At least 30 days prior to the beginning of each Contract Year, Agent/operator shall provide Seller with a non-binding written forecast of Buyers' estimated Coal requirements for such Contract Year.

(b) Annual Base Quantity. Subject to Sections 6, 13, and 15 hereof, the Annual Base Quantity of Coal for each Contract Year, which Buyers are obligated to purchase, shall be the minimum number of Btu's respectively set forth opposite such Contract Year below:

Contract Year	Annual Base Quantity in MMBtu
1993-2013	116,200,000
2014-2020	74,700,000

(c) Right of First Refusal - Unit 4. If Buyers, upon construction and commencement of operations, plan to utilize coal to operate Unit 4 between January 1, 2014 and December 31, 2020, then Buyers shall offer Seller the opportunity to provide such coal. Seller may, at its option, exercise the right to sell such quantity of Coal to Buyers on the following terms and conditions:

(i) Buyers shall obtain one or more bona fide written offers (each a "Competitive Offer") to supply coal to Unit 4 from one or more producers) not affiliated with or controlled by Buyers (each such producer an "Other Producer") and shall submit to Seller: (A) the price per MMBtu F.0.B. Unit 4 from such Competitive Offer(s) ; and, (B) a summary of the other terms and conditions of the Competitive offer(s), including, but not limited to, quality specifications, quantity, term, price adjustment and payment terms, but without revealing the identity of the Other Producer(s). Buyers shall at the same time submit to Seller a verification from the firm of certified public accountants then acting as Agent/Operator's auditor of the accuracy of the price and the summary of the Competitive Offers' terms and conditions.

(ii) If, within 10 days after receipt of such information from Buyers, Seller agrees to offer a price for coal to be delivered F.O.B. Unit 4 equal to or less than the price from one or more of the other Producer(s) and agrees to all other reasonable terms and conditions of the respective Competitive Offer (s) as stated in the summary, Buyers shall purchase such quantity of coal during such contract term from Seller at such price and on such terms and conditions. If Seller advises Buyers that it does not want to furnish any quantity to Buyers, then Buyers shall have no further obligation to Seller with respect to the purchase of coal for use at Unit 4 during the term of Buyers' contract(s) with the Other Producer(s); provided, Buyers shall not purchase all of or any portion of such quantity from any entity other than the Other Producer(s) which Buyers contracted with; and provided further, if Buyers wish to purchase all or any portion of such quantity from an entity other than the Other Producer(s) which submitted the Competitive Offer(s), it shall first afford Seller the opportunity to furnish such quantity by following the procedures set forth in paragraph (i) above.

(iii) Each time Buyers desire to purchase Coal for use in Unit 4 during the period January 1, 2014 through December 31, 2020, they shall follow the procedure set forth above.

Section 4. Deficient Quantity Charge and Payment.

(a) Deficient Quantity Charge. For Contract Year 1994 and each Contract Year thereafter, the Deficient Quantity Charge shall be calculated as follows:

$$A = B\,((AR1 + AR2 + AR3 + AR4)/4)$$

Where:

A=the Deficient Quantity Charge.
B=the previous Contract Year's Deficient Quantity Charge.

AR1=the Quarterly Adjustment Ratio calculated pursuant to Section 1(oo) hereof and in effect on January 1 of the Contract Year during which Buyers incurred the Deficient Quantity.

AR2=
the Quarterly Adjustment Ratio calculated pursuant to Section 1(oo) hereof and in effect on April 1 of the Contract Year during which Buyers incurred the Deficient Quantity.

AR3=
the Quarterly Adjustment Ratio calculated pursuant to Section 1(oo) hereof and in effect on July 1 of the Contract Year during which Buyers incurred the Deficient Quantity.

AR4= the Quarterly Adjustment Ratio calculated pursuant to Section 1(oo) hereof and in effect on October 1 of the Contract Year during which Buyers incurred the Deficient Quantity.

(b) Deficient Quantity Payment. If, during any Contract Year, Buyers incur Deficient Quantity, then they shall pay Seller an amount determined by multiplying the Deficient Quantity Charge for such Contract Year by the Deficient Quantity. Such amount shall be paid by Buyers in six consecutive equal monthly installments beginning with the first such installment due and payable on or before April 15 of the Contract Year succeeding the Contract Year in which the Deficient Quantity is incurred. Seller, on or before March 1 of such succeeding Contract Year, shall furnish Buyers with an invoice showing the total and monthly amounts due for such Deficient Quantity along with any appropriate documentation supporting the calculation of such amounts. Exhibit I attached hereto and hereby made a part hereof is representative of the actual method and procedure which Buyers and Seller have agreed shall be followed in calculating the Deficient Quantity payment for any applicable Contract Year.

Section 5. Source and Dedication; Buyers' Request for Belle Ayr Mine Coal; Alternate Source Coal; Loading; Deliveries; Title and Risk of Loss.

(a) Source and Dedication. Basic Source Coal to be delivered by Seller under this Agreement shall be from the Mine; provided, Seller shall have the right at any time, and from time to time, to deliver Coal from Seller's Belle Ayr Mine located near Gillette, Wyoming and shown on Exhibit A hereto to be used by itself or blended with Coal at the Mine; and all such Coal shall be considered to be Basic Source Coal for all purposes hereunder; provided further, if Seller delivers any Basic Source Coal from the Belle Ayr Mine or blends Belle Ayr Coal with Coal at the Mine, it shall notify Agent/Operator in writing prior to the loading of any such Coal or anytime (i) a change is made to return Coal sourcing to the Mine or (ii) it discontinues blending at the Mine. Seller hereby dedicates to Buyers the total quantities of Coal from the Mine that are required, or may be required, to be delivered to Buyers in order for Seller to fulfill the commitments undertaken by it under this Agreement.

(b) Buyers' Request for Belle Ayr Mine Coal. Buyers shall have the right at any time, and from time to time, to request that Seller deliver Coal during each Contract Year from the Belle Ayr Mine. If Seller, in its sole discretion, agrees to deliver such requested quantity of Coal or portion thereof then the applicable Additional Charge shall be added to the then applicable Price or Incremental Price.

(c) Alternate Source Coal. (i) Seller, at all times during the Term, shall have the right, but not the obligation, to deliver to Buyers all or part of the Annual Base Quantity from alternate sources ("Alternate Source Coal") without regard to whether or not the source mine or mines are owned or controlled by Seller ("Alternate Source Mines"), so long as such Alternate Source Coal: (A) is delivered to the Energy Center at a cost per MMBtu (defined as including cost of Alternate Source Coal, transportation, loss in transit, any required chemical additive and rail equipment and/or any other items required to deliver Coal in a usable form and including the Utilization Cost) not higher than the cost per MmBtu of Mine Coal delivered to the Energy Center; (B) is of substantially the same or better quality and has substantially the same or better characteristics as required for Basic Source Coal pursuant to Section 6(a) hereof; (C) enables Buyers, by performance or by compromise agreeable to Buyers, Seller and Buyers' rail carrier, to comply with Buyers' obligations under transportation agreements in existence and in effect at the time of delivery; and (D) has been approved by Buyers in their reasonable discretion pursuant to the procedures set forth below.

(ii) In addition, Seller's right to supply Alternate Source Coal is subject to the following conditions:

(A) At any time, and from time to time, Seller, if it desires to supply Alternate Source Coal, shall request Agent/Operator's approval for the delivery of Alternate Source Coal. At the time of such request Seller shall provide Agent/Operator with the proximate and ultimate analyses of such Coal and shall make available quantities of such Alternate Source Coal as Agent/operator may reasonably request for purposes of analyzing and testing, including test burns in the Energy Center. All such test Coal shall be priced as though it was Alternate Source Coal purchased hereunder by Agent/Operator. Agent/Operator shall notify Seller of its approval or disapproval of such Alternate Source Coal within 30 days of the later of its receipt of (A) Seller's request or (B) the last shipment of such Alternate Source Coal for the test burn. If Agent/Operator has notified Seller that it has approved such Alternate Source Coal, it shall also advise Seller in such notice of the Utilization Cost. Such Utilization Cost shall be fixed and firm for a period of twelve months from the date Agent/Operator so notifies Seller. If Seller desires to deliver such Alternate Source Coal beyond the twelve month period, it shall notify Buyers at least 90 days prior to the expiration of such twelve month period and Buyers, within 60 days of receipt of such notice, shall advise Seller of the Utilization Cost to be effective during the ensuing twelve month period.

(B) When securing an Alternate Source Coal for shipment to Agent/Operator, Seller shall also secure for Agent/Operator access to and the right to inspect the mining, weighing, sampling and other applicable operations of the Alternate Source Mine.

(C) The price payable by Buyers for Alternate Source Coal, taking into account the Utilization Cost, shall be calculated pursuant to the procedure set forth in Exhibit 0 attached hereto and hereby made a part hereof; provided, if the parties are unable to agree on the Utilization Cost from such Alternate Source Coal and Seller desires to deliver Alternate Source Coal as the result of operational problems, including coal quality, at the Mine or Belle Ayr Mine, then pending resolution of such Utilization Cost, Buyers will take the Alternate Source Coal for such period as long as such Coal meets the other conditions set forth in this section 5(c); provided further, the price for Alternate Source Coal shall not exceed the Price less the Utilization Cost.

(d) Railcar Loading; Rail Tariff. The Coal to be sold and delivered hereunder shall be loaded F.O.B. railcars at the Mine, Belle Ayr Mine or Alternate Source Mine with freight charges paid by Buyers. Coal shall be loaded into railcars provided by Buyers in accordance with the applicable tariff and/or contract requirements of Buyers, rail carrier(s) for transportation by rail to the Energy Center. Seller agrees to pay all costs, penalties, or increases in freight charges incurred solely due to Seller's failure to comply with those applicable tariff and/or contract requirements relative to loading and weighing time and loaded railcar weight which requirements (i) are set forth in Exhibit M attached hereto and hereby made a part hereof or (ii) might be modified or changed in the future and consented to in writing by Seller, which consent shall not unreasonably be withheld; provided, Seller shall not have to incur any increased cost in order to comply with such new requirements.

(e) Title and Risk of Loss. Delivery and title to the Coal shall pass to Buyers when a loaded unit train departs the Mine, Belle Ayr Mine or Alternate Source Mine, if applicable, for its ultimate destination. Risk of loss shall follow title.

(f) Regular Deliveries. Subject to other provisions of this Agreement and taking into account the regularly scheduled holidays and vacation periods of the employees at the Mine, deliveries of Coal hereunder shall be made in approximately equal weekly quantities. Such delivery schedules may be adjusted at any time by mutual agreement between the parties.

Section 6. Quality of Coal.

(a) Coal Specifications. Except if and to the extent that Seller and Buyers may from time to time agree in writing, Coal to be supplied hereunder shall be:

(i) substantially free from impurities such as, but not limited to, bone, slate, earth, rock, pyrite, wood, tramp metal and mine debris;

(ii) sized to a top size of two inches (2"); and

(iii) of a typical weighted average quality over any monthly period substantially equal to the following specifications, on an "as received basis", as established by analyses of samples taken and analyzed as provided in Section 11 hereof, to-wit:

Coal Characteristics	Specifications
Moisture	31.1%
Ash	5.85 lbs./MMBtu
Volatile Matter	31.0%
Fixed Carbon	33.0%
Sulfur	0.43 lbs./MMBtu
Calorific Value	8300 Btu's/lb.
Ash Fusion (Reducing Atmosphere)	
Initial Deformation	2185 degrees F
Softening (H=W)	2225 degrees F
Softening (H=W/2 W)	2265 degrees F
Fluid	2300 degrees F
Grindability (Hardgrove Index) 58 (at 20% moisture)	
Free Swelling Index	0

(b) Off-Specification Coal. Seller shall take all reasonable necessary precautions in order to avoid delivering Coal to Buyers that does not meet the above specifications; however, in the event Off-Specification Coal is delivered, Buyers shall pay for all such Off-Specification Coal at a price equivalent to 90 percent of the Price or Incremental Price, as the case may be. In the event the monthly weighted average analysis shows that Off-Specification Coal has been delivered, Buyers have the option to suspend all further shipments until Buyers are reasonably assured by Seller that Seller will be able to deliver Coal which will meet the specifications as set out in Section 6(a) hereof. If Buyers suspend shipments pursuant to this Section 6(b), then the Annual Base Quantity shall be reduced by an amount equal to the product obtained by multiplying the number of days of such suspension by the result obtained by dividing the Annual Base Quantity by 365.

Section 7. Price and Incremental Price: Certain Taxes: Economic Controls.

(a) Price and Incremental Price. Buyers shall pay to Seller the Price for Annual Base Quantity Coal and the Incremental Price for Incremental Quantity Coal delivered F.O.B. railcars at the Mine, the Belle Ayr Mine or Alternate source Mine and accepted under this Agreement. The Price shall consist of the IC and RTRC and shall be calculated from time to time as provided for in Section 8(a) hereof. The Incremental Price shall consist of the ICIP and RTRCIP and shall be calculated or redetermined from time to time as provided for in Section 8(b) hereof.

(b) Certain Taxes. If any sales tax, excise tax, use tax or similar taxes applicable to the sale or use of Coal are levied at or after the point of delivery, Buyers shall either pay such taxes directly or reimburse Seller if Seller has paid such taxes.

(c) Economic Controls. In the event the effect of any adjustment or redetermination of the Price or Incremental Price provided for herein is hereafter prevented, suspended or limited by any economic controls required or established by applicable laws, rules or regulations promulgated by federal, state, county or local governmental bodies or agencies, then, upon and as of the effective date of the repeal, modification or lapse thereof, in whole or in part, the Price or Incremental Price shall be revised to give effect to all adjustments thereto and redeterminations thereof required or permitted under this Agreement but not theretofore made due to such economic controls. Such revised Price or Incremental Price shall apply (until further adjusted or redetermined from time to time) to all subsequent deliveries of Coal made hereunder.

Section 8. Calculation of Price and Incremental Price.

(a) Price Components. Beginning January 1, 1993, the Price shall consist of two components: RTRC and IC and shall be an amount equal to the sum of such components. The Price shall be calculated from time to time to reflect the respective amounts contained in the RTRC and IC components. Each of these components shall be calculated pursuant to this Section 8. An example of the operation of this Section 8 using hypothetical numbers is set forth in Exhibits B through E and Exhibit G which are attached hereto and hereby made a part hereof. Exhibits B through E and Exhibit G are representative of the actual methods and procedures which Buyers and Seller have agreed shall be followed, except as otherwise provided for in this Agreement, in making the calculations.

(i) Calculation of RTRC. The RTRC shall be an amount equal to the sum of the values of the items of the RTRC set forth in Sections 8(a)(i)(C),(D),(E),(F), and (G) hereof and any items added pursuant to Section 8(c)(i) hereof. Such values shall be calculated Quarterly beginning January 1, 1993, and at any other time that a change occurs in the respective value of any such item included in the RTRC. Calculations shall be made using actual amounts unless such actual amounts are not available in which case reasonable estimated amounts shall be used. Documentation to substantiate the use of such actual or reasonable estimated amounts shall be provided by Seller to Buyers at the time Seller notifies Buyers of any change in the RTRC. If an estimated amount for any item is used in the calculation of the RTRC, then such amount shall be reconciled with the final actual amount of such item as soon as such actual amount becomes known and, if there is a difference between the two such amounts, then an appropriate invoice shall be issued pursuant to Section 9(a) hereof.

The value for each item of the RTRC and the CP shall be solved to six decimal places. The respective values of the items of the RTRC shall be added together and the result thereof shall be rounded to four decimal places to determine the RTRC. Such calculations shall be made pursuant to the following procedures and formulas:

(A) The symbols, descriptions, units of measure and data sources used to determine values for the items of the RTRC calculated by equations, set forth in Section 8(a)(i)(B) hereof, are set forth in the RTRC EQUATION RELATED SYMBOLS TABLE below:

RTRC EQUATION RELATED SYMBOLS TABLE

Symbol	Description	Measure	Units of Data Source
BLR	Federal Black Lung Excise Tax Rate as of the date of adjustment	percent	Title 26 United States Codes Section 4121 (1992) and Title 26 Code of Federal Regulations Section 48.4121-1 (1992)
BLT	Federal Black Lung Excise Tax	MMBtu	Section 8(a)(i)(G)
CDR	Current Federal Statutory Depletion rate as of the date of the adjustment	percent	Title 26 United States Code sections 291(a)(2) and 613(b)(4) (1992)
CP	Calculated price variable	MMBtu	Section 8(a)(i)(6) hereof
FDR	Fixed Federal Statutory Depletion Rate (10%)	percent	Title 26 United States Code Section 613(b)(4) (1984)
FRT	All coal produced from Federal leases at the Mine subject to royalty assessment based on percentage of value during the three months beginning on the date of the calculation	Tons	Seller's records
IC	Indexed Component	$/MMbtu	Section 8(a)(ii) hereof
MDC	Total Direct Mining Costs at the Mine related to the adjustment period as calculated by Seller and accepted by the State of Wyoming	$	Seller's records
ORG	John Organ Royalty	$/MMBtu	Section 8(a)(i)(F) hereof
ORR	John Organ Royalty rate as of the date of the adjustment	percent	Letter of Proposed Settlement of January 18, 1969, between John E. Eunice Organ and Ayrshire Collieries Corporation
PRT	Wyoming severance taxes and Campbell County, Wyoming ad valorem taxes on production	$/MMbtu	Section 8(a)(i)(C) hereof
PRTR	Wyoming severance tax rate and the Campbell County, Wyoming ad valorem tax rate on production as of the date of the adjustment production	percent	Wyoming Statutes Section 39-6-302 (1992) and the Campbell County, Wyoming ad valorem tax rate on Article XV Section 3 of the Constitution of Wyoming
R	Federal Royalties	$/MMBtu	Section 8(a)(i)(E) hereof
RR	Federal Royalty rate at the Mine as of the	percent	Federal Coal Leases,

	date of the adjustment calculation		W-0313773
S	Statutory Depletion	$/MMBtu	Section 8(a)(i)(D) hereof
TDC	Total Direct Costs at the Mine related to the adjustment period as calculated by Seller and accepted by the State of Wyoming	$	Tax returns including all amendments filed by Seller and accepted by the Wyoming Department of Revenue
TR	Federal corporate income tax rate as of the date of the adjustment (34% in 1992)	percent	Title 26 United States Code Section 11(b)(1)(c) (1992)
TT	Total coal tonnage produced at the Mine during the three months beginning on the date of adjustment	Tons	Seller's records

(B) The equations used to determine values for items of the RTRC calculated by equations are:

(1) BLT = (CP-BLT) (BLR/100)
but not more than the statutory maximum per ton expressed as $/MMBtu based on 8300 Btu/lb.

(2) R + (CP) (RR) (FRT)/((TT) (100))

(3) PRT = (((CP-R-ORG-BLT-PRT) (MDC/TDC))+
ORG+BLT+PRT) (PRTR)/100

(4) ORG = (CP-BLT-PRT-
R+((.20) (FRT)/(TT)))) (ORR/100

(5) S = (CP-R-ORG) (FDR-CDR) (TR)/10,000

(6) CP = IC+R+ORG+PRT+BLT+S

These equations shall be solved and the equation determined items of the RTRC calculated simultaneously by direct substitution iteration until no change is noted in the sixth decimal place in each of the variables on both sides of the equal sign in each equation and the resultant items of the RTRC shall be rounded to six decimal places. The non-variable values shall be input to four decimal places. The above equations exclude the Reclamation Fee (however, it is agreed that if the current statutory amount of such Fee is changed by a New Law, then the difference between the amount imposed by the New Law and the current amount shall be included in the RTRC calculations) and Amax Land Royalties from the appropriate equations in effect on January 1, 1993, because of their inclusion in the IC. If, as a result of an action of a third party, any of the above equations no longer accurately determines the value of the applicable ' item of the RTRC, then an appropriate change in such equations) shall be made; provided, if, in calculating values for items (3), (4) and (5) of the RTRC enumerated above, a third party, as of December 31, 1992, deducted amounts for the Reclamation Fee and/or Amax Land Royalties, then amounts for the Reclamation Fee and/or Amax Land Royalties shall never be used in calculating such values hereunder and the changed equations) shall replace the appropriate above equations). In such event Seller shall submit revised equations to Buyers, along with supporting documentation, for Buyers' written approval, which shall not unreasonably be withheld.

(C) The Wyoming severance taxes and Campbell County (Wyoming) ad valorem taxes on production item of the RTRC shall be calculated by the equation specified in Section 8 (a) (i) (B) (3) hereof. An example calculation is shown on Exhibit C hereto.

(D) The statutory depletion item of the RTRC shall be calculated by the equation specified in Section 8(a)(i)(B)(5) hereof. An example calculation is shown on Exhibit C hereto.

(E) The Federal Royalty item of the RTRC shall be calculated by the equation specified in Section 8(a)(i)(B)(2) hereof. An example calculation is shown on Exhibit C hereto.

(F) The John Organ Royalty item of the RTRC shall be calculated by the equation specified in Section B(a)(i)(B)(4) hereof.

An example calculation is shown on-Exhibit C hereof.

G) The Federal Black Lung Excise Tax item of the RTRC shall be calculated by the equation specified in Section 8(a) (i) (B) (1) hereof. An example calculation is shown on Exhibit C hereto.

(ii) Adjustment of IC. As of January 1, 1993, the IC shall be $0.3455/MMBtu and shall thereafter be adjusted Quarterly during each Contract Year. The IC for an Adjustment Quarter shall be determined by multiplying the amount of the IC for the previous Quarter by the Quarterly Adjustment Ratio for such Adjustment Quarter. The product of such calculation shall be rounded to four decimal places. If any information needed for the calculation of the Quarterly Adjustment Ratio is not available until after the beginning of an Adjustment Quarter, the calculation of the Quarterly Adjustment Ratio shall be applied retroactively to the beginning of such Adjustment Quarter. Seller shall use all reasonable efforts to provide Buyers with documentation to substantiate the use of all calculations, whether based upon estimated amounts or actual amounts, together with supporting calculations and appropriate documentation, no later than 30 days prior to the beginning of the Adjustment Quarter. If an estimated amount for any item is used in the calculation of the IC, then such amount shall be reconciled with the final actual amount of such item as soon as such actual amount becomes known and, if there is a difference between the two such amounts, then an appropriate invoice shall be issued pursuant to Section 9 (a) hereof. Example calculations are shown on Exhibits D, E and G hereto.

(b) Incremental Price Calculation and Redetermination. Beginning January 1, 1993, the Incremental Price shall consist of two components: RTRCIP and ICIP and shall be an amount equal to the sum of such components. The Incremental Price shall be calculated from time to time to reflect the respective amounts contained in the RTRCIP and ICIP components. Each of these components shall be calculated pursuant to this Section 8. An - example of the operation of this Section 8 using hypothetical numbers is set forth in Exhibit B and Exhibits D through G hereto. Exhibit B and Exhibits D through G are representative of the actual methods and procedures which Buyers and Seller have agreed shall be followed, except as otherwise provided for in this Agreement, in making the calculations.

(i) Calculation of RTRCIP. The RTRCIP shall be an amount equal to the sum of the values of the items of the RTRCIP set forth in Sections 8(b) (i) (C), (D), (E),(F) and (G) hereof and any items added pursuant to Section 8 (c) (i) hereof. Such values shall be calculated Quarterly beginning January 1, 1993, and at any other time that a change occurs in the respective amount of any item included in the RTRCIP. Calculations shall be made using actual amounts unless such actual amounts are not available in which case reasonable estimated amounts shall be used. Documentation to substantiate the use of such actual or reasonable estimated amounts shall be provided by Seller to Buyers at the time Seller notifies Buyers of any change in the RTRCIP. If an estimated amount for any item is used in the calculation of the RTRCIP, then such amount shall be reconciled with the final actual amount of such item as soon as such actual amount becomes known and, if there is a difference between the two such amounts, then an appropriate invoice shall be issued pursuant to Section 9(a)hereof. The value of each item of the RTRCIP and the CIP shall be solved to six decimal places. The respective values of the items of the RTRCIP shall be added together and the result thereof, shall be rounded to four decimal places to determine the RTRCIP. Such calculations shall be made pursuant to the following procedures and formulas:

(A) The symbols, descriptions, units of measure and data sources used to determine values for the items of the RTRCIP calculated by equations, set forth in Section 8 (b) (i) (B) hereof, are set forth in the RTRCIP EQUATION RELATED SYMBOLS TABLE below:

RTRCIP EQUATION RELATED SYMBOLS TABLE

Symbol	Description	Measure	Units of Data Source
BLR	Federal Black Lung Excise Tax Rate as of the date of adjustment	percent	Title 26 United States Codes Section 4121 (1992) and Title 26 Code of Federal Regulations Section 48.4121-1 (1992)
BLT	Federal Black Lung Excise Tax	$/MMBtu	Section 8(b)(i)(G)
CDR	Current Federal Statutory Depletion rate as of the date of the adjustment	percent	Title 26 United States Code sections 29(a)(2) and 613(b)(4) (1992)
CIP	Calculated incremental price variable	$/MMBtu	Section 8(b)(i)(B)(6) hereof
FDR	Fixed Federal Statutory Depletion Rate (10%)	percent	Title 26 United States Code Section 613(b)(4) (1984)
FRT	All coal produced from Federal leases at the Mine subject to royalty assessment based on percentage of value during the three months beginning on the date of the calculation	Tons	Seller's records
ICIP	Indexed Component	$/MMbtu	Section 8(b)(ii) hereof
MDC	Total Direct Mining Costs at the Mine related to the adjustment period as calculated by Seller and accepted by the State of Wyoming	$	Seller's records
ORG	John Organ Royalty	$/MMBtu	Section 8(b)(i)(F) hereof
ORR	John Organ Royalty rate as of the date of the adjustment	percent	Letter of Proposed Settlement of January 18, 1969, between John E. Eunice Organ and Ayrshire Collieries Corporation
PRT	Wyoming severance taxes and Campbell County, Wyoming ad valorem taxes on production	$/MMbtu	Section 8(b)(i)(C) hereof
PRTR	Wyoming severance tax rate and the Campbell County, Wyoming ad valorem tax rate on production as of the date of the adjustment production	percent	Wyoming Statutes Section 39-6-302 (1992) and the Campbell County, Wyoming ad valorem tax rate on Article XV Section 3 of the Constitution of Wyoming
R	Federal Royalties	$/MMBtu	Section 8(b)(i)(E) hereof
RR	Federal Royalty rate at the Mine as of the	percent	Federal Coal Leases,

	date of the adjustment calculation		W-0313773
S	Statutory Depletion	$/MMBtu	Section 8(b)(i)(D) hereof
TDC	Total Direct Costs at the Mine related to the adjustment period as calculated by Seller and accepted by the State of Wyoming	$	Tax returns including all amendments filed by Seller and accepted by the Wyoming Department of Revenue
TR	Federal corporate income tax rate as of the date of the adjustment (34% in 1992)	percent	Title 26 United States Code Section 11(b)(1)(c) (1992)
TT	Total coal tonnage produced at the Mine during the three months beginning on the date of adjustment	Tons	Seller's records

(B) The equations used to determine values for items of the RTRCIP calculated by equations are:

(1) BLT = (CIP-BLT)(BLR/100)
but not more than the statutory maximum per ton expressed as $/MMBtu based on 8300 Btu/lb.

(2) R = (CIP)(RR)(FRT)/((TT)(100))

(3) PRT = (((CIP-R-ORG-BLT-PRT) (MDC/TDC)) +ORG+ BLT+PRT)
(PRTR) /100

(4) ORG = (CIP-BLT-PRT-R+
((.20) (FRT) / (TT))) (ORR) /100

(5) S = (CIP-R-ORG)(FDR-CDR)(TR)/10,000

(6) CIP = ICIP+R+ORG+PRT+BLT+S

These equations shall be solved and the equation determined items of the RTRCIP calculated simultaneously by direct substitution iteration until no change is noted in the sixth decimal place in each of the variables on both sides of the equal sign in each equation and the resultant items of the RTRCIP shall be rounded to six decimal places. The non-variable values shall be input to four decimal places. The above equations exclude the Reclamation Fee (however, it is agreed that if the current statutory amount of such Fee is changed by a New Law, then the difference between the amount imposed by the New Law and the current amount shall be included in the RTRCIP calculations) and Amax Land Royalties from the appropriate equations in effect on January 1, 1993, because of their inclusion in the ICIP. If, as a result of an action of a third party, any of the above equations no longer accurately determines the value of the applicable item of the RTRCIP, then an appropriate change in such equations) shall be made provided, if, in calculating values for items (3), (4) and (5) of the RTRCIP enumerated above, a third party, as of December 31, 1992, deducted amounts for the Reclamation Fee and/or Amax Land Royalties, then amounts for the Reclamation Fee and/or Amax Land Royalties shall never be used in calculating such values hereunder and the changed equations) shall replace the appropriate above equations). In such event Seller shall submit revised equations to Buyers, along with supporting documentation, for Buyers' written approval, which shall not unreasonably be withheld.

(C) The Wyoming severance taxes and Campbell County (Wyoming) ad valorem taxes on production item of the RTRCIP shall be calculated by the equation specified in Section 8(b)(i)(B)(3) hereof. An example calculation is shown on Exhibit F hereto.

(D) The statutory depletion item of the RTRCIP shall be calculated by the equation specified in Section 8(b)(i)(B)(5) hereof. An example calculation is shown on Exhibit F hereto.

(E) The Federal Royalty item of the RTRCIP shall be calculated by the equation specified in Section 8(b)(i)(B)(2) hereof. An example calculation is shown on Exhibit F hereto.

(F) The John Organ Royalty item of the RTRCIP shall be calculated by the equation specified in Section 8(b)(i)(B)(4) hereof. An example calculation is shown on Exhibit F hereto.

(G) The Federal Black Lung Excise Tax item of the RTRCIP shall be calculated by the equation specified in Section 8 (b) (i) (B) (1) hereof. An example calculation is shown on Exhibit F hereto.

(ii) Adjustment of ICIP. As of January 1, 1993, the ICIP shall be $0.1540/MMBtu and shall thereafter be adjusted Quarterly during each Contract Year. The ICIP for an Adjustment Quarter shall be determined by multiplying the amount of the ICIP for the previous Quarter by the Quarterly Adjustment Ratio for such Adjustment Quarter. The product of such calculation shall be rounded to four decimal places. If any information needed for the calculation of the Quarterly Adjustment Ratio is not available until after the beginning of an Adjustment Quarter, the calculation of the Quarterly Adjustment Ratio shall be applied retroactively to the beginning of such Adjustment Quarter. Seller shall use all reasonable efforts to provide Buyers with documentation to substantiate the use of all calculations, whether based upon estimated amounts or actual amounts, together with supporting calculations and appropriate documentation, no later than 30 days prior to the beginning of the Adjustment Quarter. If an estimated amount for any item is used in the calculation of the ICIP, then such amount shall be reconciled with the final actual amount of such item as soon as such actual amount becomes known and, if there is a difference between the two such amounts, then an appropriate invoice shall be issued pursuant to Section 9 (a) hereof. Example calculations are shown on Exhibits D, E and G hereto.

(iii) Market Redetermination. Notwithstanding anything contained to the contrary in this Agreement, and in addition to all other rights of the parties contained herein, it is agreed that a redetermination of the Incremental Price shall be made hereunder. The purpose of such redetermination is to change the Incremental Price so that it is reflective of the then current market price for similar Powder River Basin coal sold to utility purchasers buying coal for their own consumption under five year coal supply agreements commencing at the time of the redetermination for the purchase of approximately 1,000,000 tons of coal per year and containing terms and conditions as set forth in Exhibit L attached hereto and hereby made a part hereof (hereinafter such current market price referred to as the "Market Price").

Redeterminations of the Incremental Price pursuant to this Section 8(b)(iii) shall be effective on January 1, 1998, January 1, 2003, January 1, 2008, January 1, 2013 and January 1, 2018.

Redetermination shall be initiated by Buyers serving written notice to Seller of the selection of their Consultant no later than August 15 prior to the Contract Year in which such redetermination of the Incremental Price shall become effective. Upon receipt of such notice, Seller, within 10 days, shall notify Buyers of which Consultant it has chosen to determine the Market Price.

After each party has received its Consultant's determination of the Market Price, Agent/operator and

Seller shall compare their Consultants' Market Prices, on or before October 5. If either one of the Market Prices is within five percent of the simple arithmetic average of the two Consultant's Market Prices, then the simple arithmetic average of the two Market Prices shall be the Incremental Price which will be effective on such respective January 1. If neither of the Consultant's Market Price is within five percent of the simple arithmetic average, as shown on Exhibit J-1 hereto, then a third and fourth Consultant shall be selected in a random drawing from the list contained on Exhibit K hereto. The third Consultant selected shall be contacted within 10 Business Days to ascertain if such Consultant can determine a Market Price by December 1. If the third Consultant cannot make such a timely determination, then the fourth Consultant shall be contacted as soon as possible to see if it can make such a timely determination. This process shall be repeated, if necessary, until a Consultant is selected and if the process is delayed beyond the applicable January 1, the resulting Incremental Price shall be applied retroactively to such applicable January 1. Any communications with the third or fourth or subsequent Consultant must be made simultaneously by both Agent/Operator and Seller. When the Consultant has determined the Market Price, the Incremental Price, which will become effective on each respective January 1, shall be the simple arithmetic average of all three Consultant's Market Prices, as shown on Exhibit J-2 hereto. The ICIP effective on each respective January 1 shall be solved by using the Incremental Price and the formulas and non-variable inputs used to calculate each respective January 1 RTRCIP.

(c) New Laws. After December 31, 1992, Seller's Law Costs shall be calculated by Seller and the amount (whether an increase or decrease) of such change shall be included in either the RTRC or the IC as an item of cost as provided for below:

(i) Classification of Seller's Laws Cost.

(A) If an item of cost occasioned by a New Law is a specific amount per ton or other measure and is not then an item of the RTRC, then it shall become an item of and be included in the RTRC on the basis of the specific amount per ton, converted to the equivalent dollars per MMBtu based upon 8,300 Btu's per pound, retroactively to the date the New Law first affected Seller's Laws Cost.

(B) If an item of cost occasioned by a New Law is calculated as a percent of Seller's revenue from the sale of coal from the Mine less applicable deductions, if any, and is not then an item of the RTRC, then it shall become an item of and be included in the RTRC on the basis of an amount calculated pursuant to the procedures set forth in Section 8 (a) (i) (B) hereof retroactively to the date the New Law first affected Seller's Laws Cost.

(C) If an item of cost occasioned by a New Law causes Seller's operating costs at the Mine to increase decrease, then such cost shall become an item of and be included in the IC on the basis of an amount calculated pursuant to the procedures set forth in Section 8 (c) (ii) or (iii) hereof.

(D) Any Seller's Laws Cost which can not be classified in one of the preceding sections, shall be classified as either an IC or RTRC cost by mutual agreement of the parties.

(ii) IC Related Cost Reduction.

(A) If Seller's Laws Cost is classified as an IC cost and is a reduction for an item of cost, then Seller and Buyers shall agree on an estimated amount of the cost reduction and the IC shall be reduced by such amount retroactively to the date such New Law first affected Seller's Laws Cost and this estimated amount shall continue to be used in calculating the IC until Buyers and Seller agree to an amount pursuant to Section 8(c)(ii)(B) hereof.

(B) After the IC has been reduced pursuant to Section 8(c)(ii)(A) hereof for the Survey Period, the actual amount of reduction for such item of cost shall be determined. Seller shall calculate and present to Buyers, Seller's determination of the actual amount of such cost reduction for each Quarter of the Survey Period. Buyers or Buyers' representative shall have the right at Buyers' expense to review Seller's applicable records to independently calculate and present to Seller, Buyers' determination of the actual amount of such cost reduction for each Quarter of the Survey Period. Such review shall include an eight Quarter period commencing four Quarters previous to the first Quarter of the Survey Period. Buyers' review shall be completed within 120 days after Buyers or Buyers' representative has received all necessary data and information from Seller. Seller and Buyers shall then review the available-data and agree on the actual cost reduction for each Quarter of the Survey Period.

(C) After Buyers and Seller have reached an agreement pursuant to Section 8(c)(ii)(B) hereof, the Price for each Quarter of the Survey Period shall be recalculated based upon the new values of the IC (which shall reflect the actual amount of such cost reduction). The total amount paid by Buyers for Coal delivered during the Survey Period shall be compared with the total amount that would have been paid by Buyers if the recalculated Price had been in effect and Buyers' account shall either be credited or debited, as the case may be, for the amount of any difference between such total amounts.

(D) After Buyers and Seller have reached an agreement pursuant to Section 8(c)(ii)(B) hereof, the weighted average actual amount of such cost reduction for such item of cost shall be calculated for the Survey Period. For purposes of calculating the IC pursuant to Section 8(a)(ii) hereof for all Quarters subsequent to the Survey Period such weighted average actual amount of such cost reduction shall replace the estimated amount previously included in the IC for the fourth Quarter of the Survey Period.

(iii) IC Related Cost Increase.

(A) If Seller's Laws Cost is classified as an IC cost and is an increase f or an item of cost, then Seller and Buyers shall agree on an estimated amount of the cost increase and include such amount in the IC retroactively to the date the New Law first affected Seller's Laws Cost and this estimated amount shall continue to be used in calculating the IC until Buyers and Seller agree to an amount pursuant to Section 8(c)(iii)(B) hereof.

(B) After an item of cost has been included in the IC pursuant to Section 8(c)(iii)(A) hereof for the Survey Period, the actual amount of increase for such item of cost shall be determined. Seller shall calculate and present to Buyers, Seller's determination of the actual amount of such cost increase for each Quarter of the Survey Period.

Buyers or Buyers's representative shall have the right at Buyers' expense to review Seller's applicable records to independently calculate and present to Seller, Buyers' determination of the actual amount of such cost increase for each Quarter of the survey Period.

Such review shall include an eight Quarter period commencing four Quarters previous to the Quarter during which the IC was first increased and shall be completed within 120 days after Buyers or Buyers' representative has received all necessary data and information from Seller. Seller and Buyers shall then review the available data and agree on the actual cost increase for each Quarter of the Survey Period.

(C) After Buyers and Seller have reached an agreement pursuant to Section 8(c)(iii)(B) hereof, the Price for each Quarter of the Survey Period shall be recalculated based upon the new values of the IC (which shall reflect the actual amount of such cost increase). The total amount paid by Buyers for Coal delivered during the Survey Period shall be compared with the total amount that would have been paid by Buyers if the recalculated Price had been in effect and Buyers, account shall either be credited or debited, as the case may be, for the amount of any difference between such total amounts.

(D) After Buyers and Seller have reached an agreement pursuant to Section 8 (c) (iii) (B) hereof, the weighted average actual amount of such cost increase for such item of cost shall be calculated for the Survey Period. For purposes of calculating the IC pursuant to Section 8(A)(ii) hereof for the first Quarter after the Survey Period, such weighted average actual amount of such cost increase shall replace the estimated amount previously included in the IC for the fourth Quarter of the Survey Period.

(iv) ICIP and RTRCIP Adjustments. If a classification of Seller's Law Costs pursuant to Section 8(c)(i) hereof results in an adjustment in the RTRC or IC then a similar adjustment shall be made to the RTRCIP or ICIP, as the case may be. If adjustments to the RTRC or IC made pursuant to Section 8 (c) hereof result in a change in the Price, then a similar adjustment shall be made to the Incremental Price based upon the corresponding changes to the RTRCIP and the ICIP.

(d) Additional Charge Adjustment. As of January 1, 1993, the Additional Charge shall be $0.0150/MMBtu and shall thereafter be adjusted Quarterly during each Contract Year. The Additional Charge for an Adjustment Quarter shall be determined by multiplying the previous Quarter's Additional Charge by the Quarterly Adjustment Ratio for such Adjustment Quarter. The product of such calculation shall be rounded to four decimal places. If any information needed for the calculation of the Quarterly Adjustment Ratio is not available until after the beginning of an Adjustment Quarter, the calculation of the Quarterly Adjustment Ratio shall be applied retroactively to the beginning of such Adjustment Quarter. Seller shall use all reasonable efforts to provide Buyers with documentation to substantiate the use of all calculations, whether based upon estimated amounts or actual amounts, together with supporting calculations and appropriate documentations, no later than 30 days prior to the beginning of the Adjustment Quarter. An example calculation is shown on Exhibit H hereto.

(e) Procedure in the Event Indices are Discontinued or Changed. Buyers and Seller hereby agree that the indices used to adjust the Price and Incremental Price are not intended to reflect the changes in Seller's costs of providing Coal hereunder or the change in the general market price for coal. The sole purpose in using the various indices is to afford the parties a method whereby the Price and Incremental Price can be adjusted.

If any index referred to in this Agreement is changed, discontinued or unavailable for (i) four or more months out of any two consecutive Quarters, if using monthly indices, or (ii) two consecutive Quarters, if using Quarterly indices such that the current index cannot be calculated, then the parties shall undertake in good faith to agree upon a substitute index. If an index is only temporarily unavailable then said index shall be calculated as provided for in Exhibit E attached hereto and hereby made a part hereof or some other mutually agreed to method. If the base period of one or more of the indices used in this Agreement changes, such indices will continue to be used, but the index values used in the Prior Index calculation will be changed to the index values for the new base period.

Section 9. Billing and Payment.

(a) Semi-Monthly Invoicing. Each month, Seller shall

render two invoices and Buyers shall make two payments covering the quantity of Coal delivered during such month. Such quantity shall
be determined using weights determined pursuant to Section 10 hereof and calorific value determined pursuant to Section 11 hereof. The first invoice shall cover Coal delivered by Seller during the first 15 days of the month and shall be mailed to Buyers within five Business Days thereafter. Buyers shall pay the first invoice within nine Business Days of the date upon which such first invoice is received. The second invoice shall cover Coal delivered by Seller from the 16th day to the last day of the month and shall be mailed to Buyers within five Business Days after the last day of the month. Buyers shall pay the second invoice within nine Business Days of the date upon which such second invoice is received. Invoices or credit memorandums for retroactive price adjustments and other exceptional circumstance shall be rendered by Seller as promptly as possible. Buyers shall make payment on such invoices within nine Business Days of receipt of an invoice.

(b) Monthly Allocation of Annual Base Quantity and Incremental Quantity. The Annual Base Quantity shall be apportioned monthly by dividing the Annual Base Quantity by 365 and multiplying the result by the number of days in each month, assuming that February always has 28 days in it. The result for each month shall be called the Monthly Base Quantity. In any month where the quantity of Coal shipped exceeds the Monthly Base Quantity, the quantity of Coal which exceeds the Monthly Base Quantity shall be deemed to be Incremental Quantity Coal. Such Incremental Quantity Coal shall be invoiced at the applicable Incremental Price in the second invoice of each month as provided in Section 9 (a) hereof.

(c) Annual True-up of the Annual Base Quantity. The amount paid by Buyers for the Annual Base Quantity shall be trued-up at the end of each Contract Year if: (i) Buyers, during any Contract Year, fail to take delivery of the Annual Base Quantity (less any adjustments allowed pursuant to the terms of this Agreement) and have been invoiced for Incremental Quantity Coal during the Contract Year, Buyers shall pay to Seller the difference between the Price and the Incremental Price, as the Price and Incremental Price existed on December 31 of the Contract Year, multiplied by the quantity of Incremental Quantity Coal invoiced by Seller during such Contract Year pursuant to Section 9(b) above; or (ii) Buyers, during any Contract Year, take delivery of more than the Annual Base Quantity (less any adjustments allowed pursuant to the terms of this Agreement) and the quantity of Coal invoiced by Seller at the applicable Price during such Contract Year is less than the Annual Base Quantity (less any adjustments allowed pursuant to the terms of this Agreement), then Buyers shall pay to Seller the difference between the Price and the Incremental Price, as those Prices existed on December 31 of such Contract Year, multiplied by the difference between the Annual Base Quantity (less any adjustments allowed pursuant to the terms of this Agreement) and the quantity of Coal invoiced by Seller at the applicable Price during such Contract Year. Seller shall invoice Buyers for any amount to be paid under the provisions of this Section 9(c) within 10 Business Days after the end of the Contract Year. Buyers shall pay such amount within 15 Business Days after receipt of such invoice. Example calculations of the true-up are set forth in Exhibit N hereto.

(d) Method of Payment. All payments required by this Section 9 shall be made by electronic funds transfer via ACH in U.S. currency for the invoiced amount to the account of Seller numbered 72-51807 at Continental Illinois National Bank, ABA Number 071-000039, Chicago, Illinois 60693 or any other bank and account specified by Seller.

Section 10. Weights.

(a) Weights. The weights of the Coal delivered hereunder shall be determined on Seller's Scales at the point of delivery. The weights thus determined shall be accepted as the weight of Coal for which invoices are to be rendered and payments made in accordance with Section 9 hereof. Seller shall furnish the railroad transporting the Coal with copies of the weights thereby determined in accordance with the rail tariff or contract in effect at any given time. Seller's Scales shall be inspected and certified by the State of Wyoming or an entity mutually agreed upon by Buyers and Seller at intervals of approximately six months and Agent/operator shall be furnished with a copy of the certification. Seller shall use its best efforts to notify Agent/Operator approximately 15 Business Days prior to any scale inspection and certification.

(b) Missed Weights. In the event that 50 percent or more of the individual railcar weights from a unit train are available from Seller's Scales, the average of the available railcar weights from that unit train will be used for any unavailable weights. In the event that less than 50 percent of the individual railcar weights from a unit train are available from Seller's Scales, the average railcar weights from the previous 10 unit trains comprised of similar railcars from the same Coal source shipped to the Energy Center will be used for any unavailable weights.

(c) Weighing Audits and Adjustments. Buyers shall have the right to have a representative present at any and all times to observe weighing of the Coal and inspection and certification of Seller's Scales. If any party should at any time question the accuracy of Seller's Scales, such party may request a prompt test of Seller's Scales at its expense by the State of Wyoming or an entity mutually agreed upon by Agent/Operator and Seller. If any such test reveals an error in weight in excess of one and one-half percent, then the weights of Coal shipped during one-half of the period since the last preceding test shall be adjusted by the amount of the error shown, an appropriate debit or credit memorandum shall be furnished to Buyers by Seller and Seller's Scales shall be promptly adjusted at Seller's expense.

Section 11. Sampling and Analysis.

(a) Sampling Procedure. Coal to be delivered hereunder shall be sampled at the Mine, Belle Ayr Mine or Alternate Source Mine on a continuous basis:

(i) at the batch loading sampling system or

(ii) prior to ultimate loading into railcars.

Such sampling shall be performed in accordance with methods approved by ASTM, as the same may be supplemented or modified from time to time, or by such other methods as may mutually be agreed upon by Seller and Buyers. Gross samples of Coal so taken shall represent a unit train shipment; be representative of, and identified as to, each shipment of Coal delivered hereunder to Buyers; and be taken by equipment and in manners that meet the requirements of ASTM Standard D2234 (Standard Test Methods for Collection of a Gross Sample of Coal). Sampling may also be done by Buyers at destination. Buyers and Seller shall each have the right to have a representative present in order to observe any sampling and analysis done by the other and to take check samples of the Coal. All of Seller's samples shall be divided into three parts in the manner specified by ASTM Standard D2013 (Standard Method of Preparing Coal Samples for Analysis) and put into suitable airtight containers. One part shall be retained and analyzed by Seller pursuant to applicable ASTM Standards; one part shall be delivered to Agent/Operator or Buyers' designee by mutually agreeable means and analyzed by Buyers pursuant to applicable ASTM Standards; and the third part shall be retained by Seller in one of the aforesaid containers, properly sealed and labeled, for not less than 30 days after the last day of the month in which the sample was taken, to be analyzed if a dispute arises due to a difference between Buyers' and Seller's analysis.

(b) Analysis Procedures. Seller shall perform a "short proximate" (for moisture, ash, sulfur and gross calorific value) analysis and any other analyses mutually agreed upon for each shipment as soon as practicable upon completion of loading and shall notify Agent/Operator of the results thereof prior to receipt of the Coal at the Energy Center. The analysis methods for moisture, ash, sulfur, gross calorific value and coal size designation shall be performed in accordance with ASTM Standards D3302 (Standard Test Method for Total Moisture in Coal), D3174 (Standard Test Method for Ash in the Analysis Sample of Coal and Coke from Coal), D4239 (Standard Test Methods for Sulfur in the Analysis Sample of Coal and Coke Using High Temperature Tube Furnace Combustion Methods), D3286 (Standard Test Method for Gross Calorific Value of Coal and Coke by the Isoperibol Bomb Calorimeter) and D4749 (Standard Test Method for Performing the Sieve Analysis of Coal and Designating Coal Size). The procedure for determining grindability shall be agreed to in writing by Buyers and Seller. Each party hereto shall assume the cost of all sampling and analyses performed by it. The analysis of the third part of any sample, should its analysis be found necessary, shall be made by an independent commercial testing laboratory (pursuant to applicable ASTM Standards), mutually chosen, and the results of such analysis shall be controlling. The cost of the analysis made by such commercial laboratory shall be shared equally by Seller and Buyers.

(c) Analysis Reports. Seller shall mail copies of each shipment analysis and monthly analyses to Agent/Operator as completed and, further, shall furnish a monthly report to Agent/Operator, including a summary of the individual shipment analyses and weights serving as the basis for invoicing.
Such analyses shall be deemed acceptable and binding unless protested by Agent/Operator within 30 days after receipt of the

applicable monthly report.

Section 12. Records and Audits.

(a) Recordkeeping. Seller shall keep accurate and satisfactory records and books of account in compliance with generally accepted accounting principles showing all weights and analyses of Coal, costs, payments, invoices, and/or revisions, adjustments, credits, debits pertaining to Price, Incremental Price, Deficient Quantity Charge, Additional Charge and annual true-up of Annual Base Quantity pursuant to Section 9(c) hereof and all other information and data required for the purposes of this Agreement ("Records").

(b) Records' Revisions - Calculations. Each time the Records are revised in accordance with this Agreement and at any other time upon 30 days' notice in writing from Buyers, Seller shall furnish to Buyers a detailed statement showing the revisions and/or calculations of the Records and the basis thereof.

(c) Right to Audit. At all reasonable times, Agent/operator shall have the right to have the applicable Records audited at Agent/Operator's expense for the purpose of verifying all Records. Such audit shall be mutually scheduled at least 30 days prior to the start of the Audit.

(d) Right to Audit Invoiced Items. The Invoiced Items shall consist of the Price, Incremental Price, Deficient Quantity Charge, Additional Charge and any annual true-up payment. The Invoiced Items shall be binding upon Buyers unless the audit is completed, the written audit report is submitted to Seller, and Buyers take exception to said Invoiced Items within one year of the end of the Contract Year in which any change was made to an Invoiced Item. At Agent/Operator's option any audit shall be made:

(i) by the nationally recognized firm of certified public accountants as shall then be retained by Seller or Buyers or;

(ii) by Buyers' internal audit staffs.

Such audit report shall set forth, in reasonable detail, all data necessary to verify any such adjustments of the Invoiced Items. Any errors made by Seller in making such adjustments as disclosed by any such audit shall be promptly corrected by making appropriate retroactive changes, except that claimed errors resulting from an interpretation of this Agreement by such auditors not agreed to by Seller's General Counsel shall be subject to resolution pursuant to Section 16 hereof.

Section 13. Force Majeure.

(a) Defined. As used herein, the term "Force Majeure shall mean any and all causes beyond the control and without fault or negligence of the party affected thereby, including, without limitation, acts of God, acts or orders of public authorities (including civil and military authorities and courts of competent jurisdiction) , acts of the public enemy, embargoes, insurrections, riots, labor disputes, labor or material shortages, fires, explosions, floods, river freeze-ups, breakdowns of or damage to plants, equipment or facilities (including emergency outages of equipment or facilities to make repairs to avoid breakdowns thereof or damage thereto) which wholly or partially prevent or interfere with the mining, hauling, processing or loading of Coal by Seller or the receiving, transporting and/or delivering by the carrier thereof, or the utilizing thereof by Buyers.

(b) Effect Hereunder. If, because of Force Majeure, any party hereto is unable to carry out any of its obligations under this Agreement (other than the obligation of a party to pay money in connection with the performance of this Agreement), and if such party shall promptly give to the other parties concerned written notice of such Force Majeure, then the obligation of the party giving such notice shall be suspended to the extent made necessary by such Force Majeure and during its continuance; provided, the party giving such notice shall use its best efforts to eliminate the cause of such Force Majeure insofar as possible with a minimum of delay; provided further, any party shall have the right to settle or resolve any labor dispute with its employees in its sole discretion. The parties receiving notice shall, within 30 days, accept or reject the claim of Force Majeure; provided, such party shall have been afforded reasonable time and access to appropriate personnel and records to investigate the Force Majeure.

(c) Deficiencies in Delivery. Any deficiencies in delivery of Coal hereunder caused by a Force Majeure which are related to the transportation of Coal from the Mine, Belle Ayr Mine or Alternate Source Mine to the Energy Center, except where Buyers have received notice from the rail carrier transporting Coal that it has incurred a Force Majeure under the rail tariff or contract, shall be made up as soon as possible unless such Force Majeure has a duration of 7 or more consecutive days in which case only that part of the deficiency related to the first 7 days of such Force Majeure will have to be made up. All other deficiencies in deliveries of Coal hereunder caused by Force majeure shall not be made up except by mutual consent. Any quantity of Coal that would have been shipped during a period of Force Majeure shall be credited against the Annual Base Quantity of Coal (by an amount equal to the product obtained by multiplying the number of days of such suspension by the result obtained by dividing the Annual Base Quantity by 365). In the event Force Majeure causes only a partial reduction in the total quantity of Coal Seller can deliver, Seller shall deliver to Buyers its pro rata share of the coal produced from the Mine, Belle Ayr Mine or Alternate Source Mine, if applicable, during the continuance of such partial reduction.

(d) Rights to Suspend and Purchase and/or Sell to Others. Either party hereto shall have the right to elect to suspend the purchase or sale of Coal, as the case may be, for the period of time during which such Force Majeure may exist, and Buyers, if they so elect, in the case of an event of Force Majeure (i) declared by Seller without regard to duration or (ii) caused by the inability of Buyers' contract rail carrier(s) to transport Coal from the Mine, Belle Ayr Mine or Alternate Source Mine to the Energy Center for a period of 14 or more consecutive days, shall have the right during such period to purchase coal from other sources and Seller, if it so elects, shall have the right during such period to sell coal to others. The quantity of coal so purchased from other sources shall be credited against the Annual Base Quantity

If Buyers suspend shipments pursuant to this Section 13, then the Annual Base Quantity shall be reduced by an amount equal to the product obtained by multiplying the number of days of such suspension by the result obtained by dividing the Annual Base Quantity by 365.

(e) Right to Terminate Agreement. Notwithstanding the foregoing, in the event the party which gave notice of an event of Force Majeure which has caused such party to be unable to comply substantially with such party's obligations hereunder has not substantially eliminated such Force Majeure within 12 months after so notifying the other party, such other party shall have the right, at its option, to terminate this Agreement without any penalty by notifying the party which gave such notice of Force Majeure of its election to do so. Any such termination shall be effective 30 days after the giving of such notice.

(f) Exception to Force Majeure. Notwithstanding the foregoing provisions of this Section 13, it is expressly understood that any prohibition to take deliveries of, or to utilize Coal subject hereto, which is imposed upon Buyers by means of laws, regulations or orders of a court or administrative body, whether or not such event is beyond the control of Buyers, shall not for the purposes herein negate the provisions set forth in Section 15 hereof.

Section 14. Relief From Economic Hardship.

(a) Notice Required. Seller and Buyers acknowledge the possibility of either party sustaining an economic hardship under this Agreement because of conditions which were unforeseeable on January 1, 1993. At any time either party believes it has sustained an economic hardship under this Agreement and wishes to invoke the provisions of this Section 14 to obtain relief, if any, it shall give notice in writing to the other party setting forth documentary proof of the following:

(i) the existence, nature, cause, extent and impact of such economic hardship; and

(ii) the facts establishing that the conditions causing such economic hardship were unforeseeable.

The party sending such notice shall also state the relief which it considers reasonable and appropriate to eliminate such economic hardship.

(b) Consideration of Request. Upon receipt of the notice set forth above, the' party receiving such notice shall consider the documentary proof submitted and any other relevant matters, and if (subject to the provisions of section 14(c) hereof), it, in its judgement, finds that the party sending such notice has sustained an economic hardship due to the cause stated in such notice and is entitled to relief hereunder, the party receiving such notice shall give reasonable and appropriate relief to the party sustaining the economic hardship. The party receiving such notice shall not arbitrarily refuse to find that the other party has sustained an economic hardship nor arbitrarily deny reasonable and appropriate relief to eliminate such hardship if found to exist.

(c) Exceptions. Economic hardship arising from any of the following types of causes or conditions shall not be grounds for relief hereunder:

(i) where the cause or condition is provided for in this Agreement;

(ii) where the cause or condition results from a matter involving the internal operations of the party claiming that it has sustained an economic hardship;

(iii) changes in the market for coal resulting from competitive factors;

(iv) availability or costs of alternative fuels; or

(v) the prohibition to take deliveries of, or to utilize the Coal subject hereto, the effect of which is provided for in Section 15 hereof.

(d) Effect of Refusal. If the party receiving a request referred to in Section 14(a) hereof, (i) elects to negotiate regarding the matters set forth in such request but an appropriate amendment of this Agreement regarding such matters has not been fully executed within 90 days following the date of such request, or (ii) refuses to agree to or negotiate regarding such matters, then the party which made such request may, with the concurrence of the other party, submit such matters to arbitration pursuant to Section 16 hereof or, if the other party does not agree to submit such matters to arbitration hereunder, exercise any other right or remedies available to it at law or in equity.

Section 15. Compliance with Anti-Pollution Laws and Regulations, etc.

(a) Termination Charge. The parties hereto recognize that, during the Term, legislative, administrative or regulatory bodies or courts having competent jurisdiction over the subject matter herein may enact laws, regulations, or issue orders such as, but not limited to, those relating to air pollution, the effect of which will make it impossible or impractical for Buyers to utilize the Coal subject hereto without substantially changing or altering its utilization, equipment or transportation to the Energy Center. Any such laws, regulations or orders may pertain to, but would not necessarily be limited to, sulfur content of the Coal. If any such laws, regulations or orders are imposed and, as a result thereof, Buyers, in their sole judgment, decide that it will be to their best interest not to utilize the Coal subject hereto, notwithstanding the provisions of this Agreement to the contrary, Buyers shall have the right to terminate this Agreement; provided, before Buyers can terminate this Agreement pursuant to this Section 15, Buyers and Seller shall meet to attempt to develop a plan that would allow Buyers to continue to utilize the Coal under this Agreement. Seller shall pay all costs to develop any plan contemplated by this Section 15, including, but not limited to, any professional services incurred by Buyers. The plan design and costing shall be approved by Buyers in their sole discretion. The plan design, development and implementation cost shall be paid by Seller, in its sole discretion. If Seller refuses to pay the total plan design, development and implementation cost, then Buyers may terminate this Agreement pursuant to this Section 15; provided, Buyers agree to pay Seller an annual termination charge ("Termination Charge") for the remaining life of this Agreement. The Termination Charge shall be equal to $0.0120 per MMBtu multiplied by the Annual Base Quantity. During any period in which Buyers are obligated to pay the Termination Charge, Seller shall use its reasonable efforts to sell the Coal which Buyers are obligated to purchase hereunder to others.

(b) Termination Charge Reduction. After Seller has shipped all of the coal contracted from the Mine to others in any Contract Year, should Seller sell any of the Coal which Buyers were obligated to purchase hereunder during said Contract Year to others at a sales price, which is greater than the Price that would have been in effect for such Contract Year, then, the Termination Charge shall be reduced by an amount equal to the product of the difference between such sales price and Price multiplied by the quantity of such coal sold to others.

(c) Termination Charge - Effect of Other Contracts. In the event there are other agreements for coal produced at the Mine that contain a similar termination charge that are also terminated, the portion of said contracted quantity that is sold shall be prorated. Said credits are to become effective for all coal sold over and above the total unaffected portion of the Mine's contracted annual production. During any period in which

Buyers are obligated to pay the Termination Charge, Seller shall use its reasonable efforts to sell the entire output of the Mine to others.

(d) Termination Charge - Seller's Obligation/Buyers' Recourse. Rejection by Seller of a bona fide offer to purchase coal at a price at least equal to that which would then be currently effective under this Agreement shall relieve Buyers of their obligation to pay the Termination Charge attributable to said quantity. Seller shall keep Buyers informed as to offers and sales of said coal.

Section 16. Arbitration.

(a) Pre-Arbitration Procedure. With respect to any controversy, claim, counterclaim, dispute, difference or misunderstanding arising out of or relating to the interpretation or application of any term or provision of this Agreement ("Dispute") any party may provide written notice to all the other parties by certified mail, return receipt request ("Notice") of the existence of a Dispute. The parties shall for a period of 30 calendar days following the date of the Notice that a Dispute exists engage in good faith discussions and negotiations in an attempt to resolve such Dispute. If, by the end of such 30 day period, unless such period is extended by mutual agreement of the parties, the parties have been unable to resolve such Dispute, they shall have a period of 15 calendar days to mutually agree to arbitrate such Dispute pursuant to the procedure set forth below. If, at the end of such 15 day period the parties have not mutually agreed to arbitrate such Dispute, then such Dispute may be resolved in any federal or state court located in the State of Colorado or the appellate courts thereof.

(b) Arbitration Procedure. Any arbitration hereunder shall be subject to and conducted pursuant to the procedures set forth in the Rules for Commercial Arbitration of the American Arbitration Association and the Federal Arbitration Act; provided, the parties shall agree prior to arbitration as to whether or not the arbitration award or decision shall be binding upon the parties.

Section 17. Notices.

(a) Notices to be in writing; Exceptions; Methods of Delivery. Any notice, request, consent, demand, report or statement, which is given to or made upon either party hereto by the other party hereto under any of the provisions of this Agreement, shall be in writing unless it is otherwise specifically provided herein, and shall be treated as duly delivered when the same is either (i) personally delivered to the President or a Vice President of Buyers in case of a notice to be given Buyers, or personally delivered to the President or a Vice President of Seller in the case of a notice to be given to Seller, or (ii) deposited in the United States mail, registered or certified, postage prepaid, and properly addressed as follows;

If the notice is to Buyers:
Western Resources, Inc.
P. 0. Box 889
Topeka, Kansas 66601
Attention: Executive Vice President - Electric
Production

With a copy to:

Western Resources, Inc.
P. 0. Box 889
Topeka, Kansas 66601
Attention: Director, Fuels

or to such other officer or such other address as Buyers shall have designated by due notice to Seller; and

If the notice is to Seller;

Amax Coal West, Inc.
165 S. Union Boulevard
Suite 1000
P.O. Box 280219
Lakewood, Colorado 80228-0219
Attention: Vice President,
Law and Governmental Affairs

or to such other officer or such other address as Seller shall have designated by due notice to Buyers.

(b) Notices as to Operating Matters. Any notice, request or demand pertaining to matters of an operating nature may be delivered by mail, messenger, telephone, telegraph, facsimile, electronic communications or orally to such agent of the party hereto being notified as may be appropriate and, if given by telephone, telegraph or orally, shall be confirmed in writing as soon as practicable thereafter, if the party to whom the notice is given so requests in any particular instance.

Section 18. Efficient and Economical operations.

Seller covenants that all of its activities relating to the production, sale and delivery of Coal subject hereto and activities relating to a New Law in Section 8(c) hereof shall, at all times, be conducted efficiently, economically and in such manner to be consistent with good and standard operating practices and procedures.

Section 19. Successors and Assigns.

This Agreement shall inure to the benefit of and be binding upon the parties hereto and their respective successors and assigns; provided, this Agreement may not be assigned by either Seller or Buyers without the written consent of all other parties, except

(i) an assignment of the Mine and Belle Ayr Mine from Seller to another wholly-owned subsidiary of Amax Coal Industries, Inc. or to a wholly-owned subsidiary of Amax Energy, Inc. shall not be considered an assignment of this Agreement and

(ii) in the following cases where no such consent will be required:

(A) pledge, assignment or other security arrangement to secure indebtedness incurred for the purpose of or in connection with performance under this Agreement, specifically including any financing arrangements deemed advisable by Seller (such as development carveouts and/or production payments) or any financing arrangements deemed advisable by Buyers (such as mortgages and deeds of trust or indentures supplemental thereto relating to the Energy Center);

(B) assignment to a successor in interest of a part or all of the assets of any party hereto by way of a merger, consolidation, sale of substantially all of the assets, divestiture pursuant to an order or decree of a court, or similar corporate reorganization, provided no such assignment shall be effective unless and until such assignee shall assume in writing the obligations of the assignor; or

(C) assignment by any Buyer of its interest, or any part thereof, in this Agreement pursuant to partnership, joint ownership, joint venture or other arrangement with a third party or parties in connection with the ownership and/or operation of the Energy Center.

Buyers shall not unreasonably withhold their consent to assignment of this Agreement to another company affiliated with AMAX Inc., a New York corporation, provided that AMAX Inc. shall guarantee performance by such affiliate of all obligations under this Agreement.

Section 20. Several Interests, Agent/Operator and Liability of Buyers

(a) Energy Center Owners. Buyers' respective interests in the Energy Center are:

Western Resources, Inc.	64%
Kansas Gas and Electric Company	20%
Missouri Public Service, a division of UtiliCorp United Inc.	8%
WestPlains Energy, a division of utilicorp United Inc.	8%

(b) Buyers' Obligations - Several. The property and contractual interests of Buyers in, and their respective rights, duties, obligations and liabilities under this Agreement shall be several and not joint and shall be proportional to their respective interest in the Energy Center. If the respective interests of Buyers in the Energy Center change during the Term, then their respective property and contractual interests in, and their rights, duties, obligations and liabilities under this Agreement shall be adjusted accordingly upon written notice by Buyers to Seller.

(c) Agent/Operator. Agent/Operator is hereby authorized to act on behalf of all Buyers on all matters arising under this Agreement. In particular, Seller shall accept instructions and commitments of Agent/Operator and such actions by Agent/Operator shall bind all Buyers and Seller in the same manner as if the instructions or commitments were made by each Buyer on its own behalf. Any dispute any Buyer has with Seller shall be prosecuted only by Agent/operator.

Section 21. Miscellaneous Provisions.

(a) Nonwaiver. The failure of any party hereto to insist in any one or more instance upon strict performance of any provision of this Agreement by any other party hereto, or to take advantage of any of its rights hereunder, shall not be construed as a waiver by it of any such provision or the relinquishment by it of any such rights in respect of any subsequent nonperformance of such provision, but the same shall continue and remain in full force and effect.

(b) Remedies. Each remedy specifically provided for under this Agreement shall be taken and construed as cumulative and in addition to every other remedy provided for herein, by law or inequity.

(c) Amendments. Any and all amendments, supplements and modifications to this Agreement shall be in writing and signed by the parties hereto.

(d) Indemnity. Each party hereby agrees to defend, indemnify, save and hold all other parties harmless from and against all loss, cost and expense arising out of injuries to or death of any person or persons resulting from willful acts or negligence of such party, its agents and employees, except that said agreement of indemnity shall not apply to any injuries to or the death of such party's own employees acting within the scope of their employment, even though another party may have been negligent in connection with the related occurrence.

(e) Headings Not to Affect Construction. The headings to the respective sections and paragraphs of this Agreement are inserted for convenience of reference and are neither to be taken to be any part of the provisions herein nor to control or affect the meaning, construction or effect of the same.

(f) Written Instrument Contains Entire Agreement.

This written instrument contains the entire agreement between the parties hereto in respect of the subject matter, and there are no other understandings or agreements between said parties, or any of them, in respect thereof.

(g) Controlling Law and Consent to Jurisdiction.

This Agreement shall be governed by and construed according to the laws of the State of Colorado. Buyers and Seller hereby irrevocably agree any legal suit, action or proceeding (each an "Action") arising out of or relating, directly or indirectly, to this Agreement shall only be brought in the courts of the State of Colorado or the United States of America for the District of Colorado and any applicable appellate courts (collectively the "Courts") and irrevocably consents to service of process outside the territorial jurisdiction of the Courts. In addition, each party, in its own behalf, irrevocably waives (i) any objection to the laying of venue of any Action brought in the Courts, (ii) any claim that any Action brought in any Court has been brought in an inconvenient forum, and (iii) any objection, with respect to any Action brought in any Court, that such Court does not have jurisdiction over any party.

(h) Rounding of Calculations. Except as otherwise specified in this Section 21(h) all computations under this Agreement shall be rounded to four decimal places. All originally published index numbers shall not be rounded. The RTRC, IC, RTRCIP and ICIP shall be rounded to the nearest one ten-thousandth of a dollar. Tons shall be rounded to the nearest one-hundredth of a ton. All aggregate dollar and Btu amounts shown on an invoice shall be rounded to the nearest whole cent or Btu; and the Price, Incremental Price, Additional Charge and Deficient Quantity Charge shall be rounded to the nearest ten-thousandth of a dollar. However, if there is no nearest one-hundredth of a cent, tenth of a cent, cent, Btu, one ten-thousandth of a dollar or hundredth of a ton, as the case may be, then the relevant number shall be rounded to the nearest even fourth decimal place, one-hundredth of a cent, tenth of a cent, cent, Btu, one ten-thousandth of a dollar or hundredth of a ton. For example, $0.54825 would be rounded to $0.5482 and $0.54835 would be rounded to $0.5484.
provision in any other jurisdiction.

(i) Severability of Provisions. Any provision of this Agreement which is prohibited or unenforceable under federal or Colorado law shall be ineffective to the extent of such prohibition or enforceability without invalidating the remaining provisions hereof or affecting the validity or enforceability of such provision in any other jurisdiction.

(j) Execution of Counterparts. This Agreement may be simultaneously executed in any number of counterparts, and all such counterparts shall constitute but one and the same instrument.

(k) Confidentiality. All of the provisions hereof are confidential and proprietary in nature and shall not be disclosed in whole or in part by any party without the prior written consent of all parties hereto, which consent shall not be unreasonably withheld; except, (i) pursuant to any existing or future order of or upon demand of regulatory bodies having jurisdiction and their staffs, including, but not limited to disclosure to the Kansas Corporation Commission by Buyer, WestPlains Energy, under docket no. 106,850-U, dated April 19, 1977; outside accounting firms retained by a party for audit or tax purposes; outside counsel retained by a party; and any assignee or successor to the Energy Center ownership interests of Buyers; any such disclosures shall be upon a restricted, proprietary and confidential basis; or (ii) as required by law.

IN WITNESS WHEREOF, the parties have executed this Agreement in their respective corporate names, as of the date first above written.

Attest: Amax Coal West, Inc.

/s/ George Womack By: /s/
Asst. Secretary President

Attest: Western Resources, Inc.

/s/ Richard D. Terrill By: /s/ William E. Brown

Secretary
President
KPL Division

Attest: Kansas Gas and Electric Company

/s/ Richard D. Terrill By:/s/ Kent R. Brown
Secretary President
Kansas Gas and Electric
Company

Missouri Public Service, a
division of Utilicorp United,
Inc.

/s/ By:/s/
Assistant Secretary Division President

WestPlains Energy, a
division of
Utilicorp United, Inc.

/s/ By:/s/
Secretary/Assistant Division President

TRANSPORTATION-STORAGE SERVICE AGREEMENT UNDER RATE SCHEDULE TSS

THIS AGREEMENT is made and entered into this 1st day of October, 1993 by and between WILLIAMS NATURAL GAS COMPANY, a Delaware corporation, having its principal office in Tulsa, Oklahoma, hereinafter referred to as "WNG" and WESTERN RESOURCES, INC., a Kansas corporation, having its principal office in Topeka, Kansas, hereinafter referred to as "Shipper."

IN CONSIDERATION of the premises and of the mutual covenants and agreements herein contained, WNG and Shipper agree as follows:

ARTICLE I QUANTITY

1.1 Subject to the provisions of this Agreement and of WNG's Rate Schedule TSS, WNG agrees to receive such quantities of natural gas as Shipper may cause to be tendered to WNG at the Primary Receipt Point(s) designated on Exhibit A which are selected from WNG's Master Receipt Point List, as revised from time to time, for transportation and storage on a firm basis; provided, however, that in no event shall WNG be obligated to receive on any day in excess of the Maximum Daily Quantity (MDQ) for each Primary Receipt Point or of the Maximum Daily Transportation Quantity (MDTQ) for all Primary Receipt Points within any area, all as set forth on Exhibit A.

1.2 WNG agrees to deliver and Shipper agrees to accept (or cause to be accepted) at the Primary Delivery Point(s) taken from the Master Delivery Point List and designated on Exhibit B a quantity of natural gas thermally equivalent to the quantity received by WNG for transportation and withdrawn from storage as provided in Article 1.3 hereunder less appropriate reductions for fuel and loss as provided in WNG's Rate Schedule TSS; provided, however, that WNG shall not be obligated to deliver on any day quantities in excess of the MDQ for each Primary Delivery Point or in excess of the MDTQ within any area for all Primary Delivery Points, all as set forth on Exhibit B.

1.3 Subject to the provisions of this Agreement and of WNG's Rate Schedule TSS, WNG agrees to (a) inject and store such quantities of natural gas up to the Maximum Storage Quantity (MSQ) and the Maximum Daily Injection Quantity (MDIQ) as Shipper may cause to be tendered to WNG for injection into storage, less appropriate reductions for fuel and loss, and (b) withdraw such quantities of natural gas up to Shipper's gas in storage and the Maximum Daily Withdrawal Quantity (MDWQ) reflected on Exhibit C, all on a firm basis.

ARTICLE II DELIVERY POINT(S) AND DELIVERY PRESSURE

2.1 Natural gas to be delivered hereunder by WNG to or on behalf of Shipper shall be delivered at the outlet side of the measuring station(s) at or near the Delivery Point(s) designated on Exhibit B at WNG's line pressure existing at such Delivery Point(s).

ARTICLE III RATE, RATE SCHEDULE AND GENERAL TERMS AND CONDITIONS

3.1 Shipper shall pay WNG each month for all service rendered hereunder the then-effective, applicable rates and charges under WNG's Rate Schedule TSS, as such rates and charges and Rate Schedule TSS may hereafter be modified, supplemented, superseded or replaced generally or as to the service hereunder. Shipper agrees that WNG shall have the unilateral right from time to time to file with the appropriate regulatory authority and make effective changes in (a) the rates and charges applicable to service hereunder, (b) the rate schedule(s) pursuant to which service hereunder is rendered, or (c) any provision of the General Terms and Conditions incorporated by reference in such rate schedule(s); provided, however, Shipper shall have the right to protest any such changes.

3.2 This Agreement in all respects is subject to the provisions of Rate Schedule TSS, or superseding rate schedule(s), and applicable provisions of the General Terms and Conditions included by reference in said Rate Schedule TSS, all of which are by reference made a part hereof.

ARTICLE IV
TERM

4.1 This Agreement shall become effective on the date of execution and shall continue in full force and effect for an original term until 7:00 a.m., local time on October 1, 2013; provided, however, this Agreement shall be considered as renewed and extended beyond such original term for successive five (5) year terms thereafter, unless canceled, effective at the end of the primary term or at the end of any subsequent five (5) year term, by six (6) months advance written notice by either party.

4.2 This Agreement may be suspended or terminated by WNG in the event Shipper fails to pay all of the amount of any bill rendered by WNG hereunder when that amount is due; provided, however, WNG shall give Shipper and the FERC thirty (30) days

Request 0053

notice prior to any suspension or termination of service. Service may continue hereunder if within the thirty-day notice period satisfactory assurance of payment is made by Shipper in accord with Article 18 of the General Terms and Conditions. Suspension or termination of this Agreement shall not excuse Shipper's obligation to pay all demand and other charges for the original term of the
Agreement.

ARTICLE V
NOTICES

5.1 Unless otherwise agreed to in writing by the parties, any notice, request, demand, statement or bill respecting this Agreement shall be in writing and shall be deemed given when placed in the regular mail or certified mail, postage prepaid and addressed to the other party, or sent by overnight delivery service, or by facsimile, at the following addresses or facsimile numbers, respectively:

To Shipper:

Billing:

WESTERN RESOURCES, INC.
818 Kansas Ave.
Topeka, KS 66612 Attn: Gas Supply Dept.
Phone: 913/575-6377
Fax: 913/575-6405

Notices:

WESTERN RESOURCES, INC.
818 Kansas Ave.
Topeka, KS 66612 Attn: Gas Supply Dept.
Phone: 913/575-1910
Fax: 913/575-6405

To WNG:

Payments:

Williams Natural Gas Company
P. 0. Box 3288
Tulsa, OK 74101
Attention: Revenue Accounting

All Notices:

Williams Natural Gas Company
P. 0. Box 3288
Tulsa, OK 74101
Attention: Manager - Transportation Services
Fax: 918/588-3108

ARTICLE VI
MISCELLANEOUS

6.1 The interpretation, performance and enforcement of this Agreement shall be construed in accordance with the laws of the State of Oklahoma.

6.2 As of the date of execution of Exhibits A, B, and C attached to this Agreement, such executed exhibits shall be incorporated by reference as part of this Agreement. The parties may amend Exhibits A, B, and C by mutual agreement, which amendment shall be reflected in a revised Exhibit A, B, and C and shall be incorporated by reference as part of this Agreement.

6.3 Any Service Agreements under Rate Schedule TSS shall not cover service under both TSS-P and TSS-M.

6.4 OTHER THAN AS MAY BE SET FORTH HEREIN, WNG MAKES NO OTHER WARRANTIES, EXPRESSED OR IMPLIED, INCLUDING WITHOUT LIMITATION WARRANTIES OF FITNESS FOR A PARTICULAR PURPOSE OR MERCHANTABILITY.

6.5 Other Miscellaneous

IN WITNESS WHEREOF, the parties hereto have executed this Agreement as of the day and year first above written.

ATTEST: WILLIAMS NATURAL GAS COMPANY

By: By: /s/ James O. Henderson

Assistant Secretary Title: Director,
Transportation
Services

ATTEST/WITNESS: WESTERN RESOURCES, INC.

By: /s/ Stacy F.Kramer By: /s/ Richard H. Tangeman
Title Assistant Secretary Title: Assistant Vice President,
Gas Supply, As Shipper

Exhibit 10(c)
Request 0055

TRANSPORTATION-STORAGE SERVICE AGREEMENT UNDER RATE SCHEDULE TSS

THIS AGREEMENT is made and entered into this 1st day of October, 1993 by and between WILLIAMS NATURAL GAS COMPANY, a Delaware corporation, having its principal office in Tulsa, Oklahoma, hereinafter referred to as "WNG," and WESTERN RESOURCES, INC., a Kansas corporation, having its principal office in Topeka, Kansas, hereinafter referred to as "Shipper."

IN CONSIDERATION of the premises and of the mutual covenants and agreements herein contained, WNG and Shipper agree as follows:

ARTICLE I
QUANTITY

1.1 Subject to the provisions of this Agreement and of WNG's Rate Schedule TSS, WNG agrees to receive such quantities of natural gas as Shipper may cause to be tendered to WNG at the Primary Receipt Point(s) designated on Exhibit A which are selected from WNG's Master Receipt Point List, as revised from time to time, for transportation and storage on a firm basis; provided, however, that in no event shall WNG be obligated to receive on any day in excess of the Maximum Daily Quantity (MDQ) for each Primary Receipt Point or of the Maximum Daily Transportation Quantity (MDTQ) for all Primary Receipt Points within any area, all as set forth on Exhibit A.

1.2 WNG agrees to deliver and Shipper agrees to accept (or cause to be accepted) at the Primary Delivery Point(s) taken from the Master Delivery Point List and designated on Exhibit B a quantity of natural gas thermally equivalent to the quantity received by WNG for transportation and withdrawn from storage as provided in Article 1.3 hereunder less appropriate reductions for fuel and loss as provided in WNG's Rate Schedule TSS; provided, however, that WNG shall not be obligated to deliver on any day quantities in excess of the MDQ for each Primary Delivery Point or in excess of the MDTQ within any area for all Primary Delivery Points, all as set forth on Exhibit B.

1.3 Subject to the provisions of this Agreement and of WNG's Rate Schedule TSS, WNG agrees to (a) inject and store such quantities of natural gas up to the Maximum Storage Quantity (MSQ) and the Maximum Daily Injection Quantity (MDIQ) as Shipper may cause to be tendered to WNG for injection into storage, less appropriate reductions for fuel and loss, and (b) withdraw such quantities of natural gas up to Shipper's gas in storage and the Maximum Daily Withdrawal Quantity (MDWQ) reflected on Exhibit C, all on a firm basis.

Release 0055

ARTICLE II
DELIVERY POINT(S) AND DELIVERY PRESSURE

2.1 Natural gas to be delivered hereunder by WNG to or on behalf of Shipper shall be delivered at the outlet side of the measuring station (s) at or near the Delivery Point (s) designated on Exhibit 3 at WNG's line pressure existing at such Delivery Point(s).

ARTICLE III
RATE, RATE SCHEDULE AND GENERAL TERMS AND CONDITIONS

3.1 Shipper shall pay WNG each month for all service rendered hereunder the then-effective, applicable rates and charges under WNG's Rate Schedule TSS, as such rates and charges and Rate Schedule TSS may hereafter be modified, supplemented, superseded or replaced generally or as to the service hereunder. Shipper agrees that WNG shall have the unilateral right from time to time to file with the appropriate regulatory authority and make effective changes in (a) the rates and charges applicable to service hereunder, (b) the rate schedule(s) pursuant to which service hereunder is rendered, or (c) any provision of the General Terms and Conditions incorporated by reference in such rate schedule(s); provided, however, Shipper shall have the right to protest any such changes.

3.2 This Agreement in all respects is subject to the provisions of Rate Schedule TSS, or superseding rate schedule(s), and applicable provisions of the General Terms and Conditions included by reference in said Rate Schedule TSS, all of which are by reference made a part hereof.

ARTICLE IV
TERM

4.1 This Agreement shall become effective on the date of execution and shall continue in full force and effect for an original term until 7:00 a.m., local time on October 1, 1994.

4.2 This Agreement may be suspended or terminated by WNG in the event Shipper fails to pay all of the amount of any bill rendered by WNG hereunder when that amount is due; provided, however, WNG shall give Shipper and the FERC thirty (30) days notice prior to any suspension or termination of service. Service may continue hereunder if within the thirty-day notice period satisfactory assurance of payment is made by Shipper in accord with Article 18 of the General Terms and Conditions. Suspension or termination of this Agreement shall not excuse Shipper's obligation to pay all demand and other charges for the original term of the Agreement.

Request 0055

ARTICLE V
NOTICES

5.1 Unless otherwise agreed to in writing by the parties, any notice, request, demand, statement or bill respecting this Agreement shall be in writing and shall be deemed given when placed in the regular mail or certified mail, postage prepaid and addressed to the other party, or sent by overnight delivery service, or by facsimile, at the following addresses or facsimile numbers, respectively:

To Shipper:

Billing:

WESTERN RESOURCES, INC.
818 Kansas Ave.
Topeka, KS 66612 Attn: Gas Supply Dept.
Phone: 913/575-6377
Fax: 913/575-6405

Notices:

WESTERN RESOURCES, INC.
818 Kansas Ave.
Topeka, KS 66612 Attn: Gas Supply Dept.
Phone: 913/575-1910
Fax: 913/575-6405

To WNG:

Payments:

Williams Natural Gas Company
P. 0. Box 3288
Tulsa, OK 74101
Attention: Revenue Accounting

All Notices:

Williams Natural Gas Company
P. 0. Box 3288
Tulsa, OK 74101
Attention: Manager - Transportation Services

Fax: 918/588-3108

ARTICLE VI
MISCELLANEOUS

6.1 The interpretation, performance and enforcement of this Agreement shall be construed in accordance with the laws of the State of Oklahoma.

6.2 As of the date of execution of Exhibits A, B, and C attached to this Agreement, such executed exhibits shall be incorporated by reference as part of this Agreement. The parties may amend Exhibits A, B, and C by mutual agreement, which amendment shall be reflected in a revised Exhibit A, B, and C and shall be incorporated by reference as part of this Agreement.

6.3 Any Service Agreements under Rate Schedule TSS shall not cover service under both TSS-P and TSS-M.

6.4 OTHER THAN AS MAY BE SET FORTH HEREIN, WNG MAKES NO OTHER WARRANTIES, EXPRESSED OR IMPLIED, INCLUDING WITHOUT LIMITATION WARRANTIES OF FITNESS FOR A PARTICULAR PURPOSE OR MERCHANTABILITY.

6.5 Other Miscellaneous

IN WITNESS WHEREOF, the parties hereto have executed this Agreement as of the day and year first above written.

ATTEST:	WILLIAMS NATURAL GAS COMPANY
By: Assistant Secretary	By: Title
ATTEST/WITNESS:	WESTERN RESOURCES, INC.
By: /s/ Stacy F. Kramer Title Assistant Secretary	By: /s/ Richard H. Tangeman Title: Asst. Vice President, Gas Supply, As Shipper

Exhibit 10(d)
Request 0195

TRANSPORTATION-STORAGE SERVICE AGREEMENT
UNDER RATE SCHEDULE TSS

THIS AGREEMENT is made and entered into this 1st day of October, 1993 by and between WILLIAMS NATURAL GAS COMPANY, a Delaware corporation, having its principal office in Tulsa, Oklahoma, hereinafter referred to as "WNG" and WESTERN RESOURCES, INC., a Kansas corporation, having its principal office in Topeka, Kansas, hereinafter referred to as "Shipper."

IN CONSIDERATION of the premises and of the mutual covenants and agreements herein contained, WNG and Shipper agree as follows:

ARTICLE I
QUANTITY

1.1 Subject to the provisions of this Agreement and of WNG's Rate Schedule TSS, WNG agrees to receive such quantities of natural gas as Shipper may cause to be tendered to WNG at the Primary Receipt Point(s) designated on Exhibit A which are selected from WNG's Master Receipt Point List, as revised from time to time, for transportation and storage on a firm basis; provided, however, that in no event shall WNG be obligated to receive on any day in excess of the Maximum Daily Quantity (MDQ) for each Primary Receipt Point or of the Maximum Daily Transportation Quantity (MDTQ) for all Primary Receipt Points within any area, all as set forth on Exhibit A.

1.2 WNG agrees to deliver and Shipper agrees to accept (or cause to be accepted) at the Primary Delivery Point(s) taken from the Master Delivery Point List and designated on Exhibit B a quantity of natural gas thermally equivalent to the quantity received by WNG for transportation and withdrawn from storage as provided in Article 1.3 hereunder less appropriate reductions for fuel and loss as provided in WNG's Rate Schedule TSS; provided, however, that WNG shall not be obligated to deliver on any day quantities in excess of the MDQ for each Primary Delivery Point or in excess of the MDTQ within any area for all Primary Delivery Points, all as set forth on Exhibit B.

1.3 Subject to the provisions of this Agreement and of WNG's Rate Schedule TSS, WNG agrees to (a) inject and store such quantities of natural gas up to the Maximum Storage Quantity (MSQ) and the Maximum Daily Injection Quantity (MDIQ) as Shipper may cause to be tendered to WNG for injection into storage, less appropriate reductions for fuel and loss, and (b) withdraw such quantities of natural gas up to Shipper's gas in storage and the Maximum Daily Withdrawal Quantity (MDWQ) reflected on Exhibit C, all on a firm basis.

ARTICLE II
DELIVERY POINT(S) AND DELIVERY PRESSURE

2.1 Natural gas to be delivered hereunder by WNG to or on behalf of Shipper shall be delivered at the outlet side of the measuring station(s) at or near the Delivery Point(s) designated on Exhibit B at WNG's line pressure existing at such Delivery Point(s).

ARTICLE III
RATE, RATE SCHEDULE AND GENERAL TERMS AND CONDITIONS

3.1 Shipper shall pay WNG each month for all service rendered hereunder the then-effective, applicable rates and charges under WNG's Rate Schedule TSS, as such rates and charges and Rate Schedule TSS may hereafter be modified, supplemented, superseded or replaced generally or as to the service hereunder. Shipper agrees that WNG shall have the unilateral right from time to time to file with the appropriate regulatory authority and make effective changes in (a) the rates and charges applicable to service hereunder, (b) the rate schedule(s) pursuant to which service hereunder is rendered, or (c) any provision of the General Terms and Conditions incorporated by reference in such rate schedule(s); provided, however, Shipper shall have the right to protest any such changes.

3.2 This Agreement in all respects is subject to the provisions of Rate Schedule TSS, or superseding rate schedule(s), and applicable provisions of the General Terms and Conditions included by reference in said Rate Schedule TSS, all of which are by reference made a part hereof.

ARTICLE IV
TERM

4.1 This Agreement shall become effective on the date of execution and shall continue in full force and effect for an original term until 7:00 a.m., local time on October 1, 1994.

4.2 This Agreement may be suspended or terminated by WNG in the event Shipper fails to pay all of the amount of any bill rendered by WNG hereunder when that amount is due; provided, however, WNG shall give Shipper and the FERC thirty (30) days notice prior to any suspension or termination of service. Service may continue hereunder if within the thirty-day notice period satisfactory assurance of payment is made by Shipper in accord with Article 18 of the General Terms and Conditions. Suspension or termination of this Agreement shall not excuse Shipper's obligation to pay all demand and other charges for the original term of the Agreement.

ARTICLE V
NOTICES

5.1 Unless otherwise agreed to in writing by the parties, any notice, request, demand, statement or bill respecting this Agreement shall be in writing and shall be deemed given when placed in the regular mail or certified mail, postage prepaid and addressed to the other party, or sent by overnight delivery service, or by facsimile, at the following addresses or facsimile numbers, respectively:

To Shipper:

Billing:

WESTERN RESOURCES, INC.
818 Kansas Ave.
Topeka, KS 66612
Attn: Gas Supply Dept.
Phone: 913/575-6377
Fax: 913/575-6405

Notices:

WESTERN RESOURCES, INC.
818 Kansas Ave.
Topeka, KS 66612
Attn: Gas Supply Dept.
Phone: 913/575-1910
Fax: 913/575-6405

To WNG:

Payments:

Williams Natural Gas Company
P. 0. Box 3288
Tulsa, OK 74101
Attention: Revenue Accounting

All Notices:

Williams Natural Gas Company
P. 0. Box 3288
Tulsa, OK 74101
Attention: Manager - Transportation Services
Fax: 918/588-3108

ARTICLE VI
MISCELLANEOUS

6.1 The interpretation, performance and enforcement of this

Agreement shall be construed in accordance with the laws of the State of Oklahoma.

6.2 As of the date of execution of Exhibits A, B, and C attached to this Agreement, such executed exhibits shall be incorporated by reference as part of this Agreement. The parties may amend Exhibits A, B, and C by mutual agreement, which amendment shall be reflected in a revised Exhibit A, B, and C and shall be incorporated by reference as part of this Agreement.

6.3 Any Service Agreements under Rate Schedule TSS shall not cover service under both TSS-P and TSS-M.

6.4 OTHER THAN AS MAY BE SET FORTH HEREIN, WNG MAKES NO OTHER WARRANTIES, EXPRESSED OR IMPLIED, INCLUDING WITHOUT LIMITATION WARRANTIES OF FITNESS FOR A PARTICULAR PURPOSE OR MERCHANTABILITY.

6.5 Other Miscellaneous

IN WITNESS WHEREOF, the parties hereto have executed this Agreement as of the day and year first above written.

ATTEST:	WILLIAMS NATURAL GAS COMPANY
By: Assistant Secretary	By: Title
ATTEST/WITNESS:	WESTERN RESOURCES, INC.
By: /s/ Stacy F. Kramer Title Assistant Secretary	By: /s/ Richard H. Tangeman Title: Asst. Vice President, Gas Supply, As Shipper

WESTERN RESOURCES DEFERRED COMPENSATION PLAN

ARTICLE I

Purpose

The purpose of the Western Resources Deferred Compensation Plan (hereinafter referred to as the "Plan") is to allow deferral of income for a specified period and to provide funds for retirement or death for certain executive and management employees (and their beneficiaries) of Western Resources, Inc. It is intended that the Plan will aid in retaining and attracting employees of exceptional ability by providing such employees with a means to supplement their estate planning and standard of living at retirement. This Plan is intended to qualify for the exemptions described in sections 201(2), 301(a)(3), and 401(a)(1) of the Employee Retirement Income Security Act of 1974, as amended.

ARTICLE II

Definitions

For the purpose of this Plan, the following words and phrases shall have the meanings indicated, unless the context clearly indicates otherwise:

2.1 Beneficiary. "Beneficiary" means the person, persons, or entity designated by the Participant, or as provided in Article VIII, to receive any benefits payable under the Plan. Any Participant Beneficiary designation shall be made in a written instrument filed with the Human Resources Committee and shall become effective only when received in writing by the Committee.

2.2 Board. "Board" means the Board of Directors of Western Resources, Inc.

2.3 Company. "Company" means Western Resources, Inc.

2.4 Compensation. "Compensation" or "Total Compensation" means the Base Salary and Incentive Compensation payable to a Participant during the Plan Year.

(a) Base Salary. "Base Salary" means all regular remuneration for services, other than such items as Incentive Compensation, payable by the Company to a Participant in cash during a Plan Year, but before reduction for amounts deferred pursuant to this Plan or any other Plan of the Company. The Human Resources Committee shall determine whether a particular item or income constitutes Base Salary if a question arises.

(b) Incentive Compensation. "Incentive Compensation" means any cash bonus earned by a Participant in a Plan Year.

2.5 Declared Rate. "Declared Rate" means the annual percentage rate (APR) of interest to be credited to the executive's deferral account. Such rate is to be set annually by the Human Resources Committee.

2.6 Deferral Benefit. "Deferral Benefit" means the benefit payable to a Participant or Participant's Beneficiary on a date specified by the Participant in the Participation Agreement or on Participant's retirement, death, disability, or termination of employment as calculated in Article VII hereof.

2.7 Deferred Benefit Account. "Deferred Benefit Account" means the accounts maintained on the books of account of the Company for each Participant pursuant to Article IV and determined with respect to any Participation Agreement. Separate Deferred Benefit Accounts shall be maintained for each Participant. A Participant's Deferred Benefit Account shall be utilized solely as a device for the measurement and determination of the amounts to be paid to the Participant pursuant to the Plan. A Participant's Deferred Benefit Account shall not constitute or be treated as a trust fund of any kind.

2.8 Deferred Compensation Committee . "Deferred Compensation Committee" means a committee appointed by the Human Resources Committee to assist in the Administration of the Plan as provided herein.

2.9 Determination Date. "Determination Date" means the date on which the amount of a Participant's Deferred Benefit Account is determined as provided in Article VI hereof. The last day of each calendar month shall be a Determination Date.

2.10 Disability. "Disability" or "Disabled Participant" means a physical or mental condition of a Participant resulting in a determination of disability for purposes of receiving benefits under the Company's Long Term Disability Plan.

2.11 Human Resources Committee. "Human Resources Committee" means the Human Resources Committee of the Board of Directors of Western Resources, Inc.

2.12 Participant. "Participant" means any individual who is deemed eligible by the Human Resources Committee to participate in this Plan and who elects to participate by filing a Participation Agreement as provided in Article IV.

2.13 Participation Agreement. "Participation Agreement" means the agreement filed by a Participant prior to the beginning of the first period for which any of the Participant's Compensation is to be deferred pursuant to the Plan. A form of such Participation Agreement is attached hereto.

2.14 Plan Year. "Plan Year" means a twelve month period commencing January 1 and ending the following December 31. The first Plan Year shall commence on October 15, 1993 and terminate on December 31, 1993.

2.15 Retirement Date. "Retirement Date" means the first day of the month coincidental with or next following a Participant's commencement of benefits following actual retirement under either The Kansas Power and Light Company or the Retirement Plan for Employees of Kansas Gas and Electric Company.

2.16 Spouse. "Spouse" means a Participant's wife or husband who was lawfully married to the Participant at the time of the Participant's death or a determination of Participant's incompetency.

ARTICLE III

Administration

3.1 The Committees: Duties. This plan shall be administered as provided herein by both the Human Resources Committee of the Board and the Deferred Compensation Committee. Members of the committees may be Participants under this Plan. The Human Resources Committee shall also have the authority to make, amend, interpret, and enforce all appropriate rules and regulations for the administration of this Plan and decide or resolve any and all questions, including interpretation of this Plan, as may arise in connection with the Plan.

3.2 Binding Effect of Decision. The decision or action of the committees with respect to any question arising out of or in connection with the administration, interpretation, and application of the Plan and the rules and regulations promulgated hereunder shall be final, conclusive, and binding upon all persons having any interest in the Plan, unless a written appeal is received by the Human Resources Committee within sixty days of the disputed action. The appeal will be reviewed by the Human Resources Committee and the decision of the committee shall be final, conclusive, and binding on the Participant and all persons claiming by, through, or under the Participant.

ARTICLE IV

Participation

4.1 Participation. Participation in the Plan in any Plan Year shall be limited to the class of those key employees selected by the Human Resources Committee who elect to participate in the Plan by filing a Participation Agreement with the Committee. A Participation Agreement must be filed prior to December 15 immediately preceding the Plan Year in which the Participant's participation under the Agreement will commence. The election to participate shall be effective on the first day of the Plan Year following receipt of a properly completed and executed Participation Agreement.

With respect to the first Plan Year of the Plan or with respect to an individual hired or promoted during a Plan Year who thereby becomes eligible to participate herein, an initial Participation Agreement may be filed within thirty days of the notification to Participant of eligibility to participate. Such election to participate shall be effective on the first day of the month following the receipt thereof, except that elections not received on or before the 15th day of any calendar month shall be effective no earlier than the first day of the second month following the month of receipt.

To participate in any subsequent Plan Year, a Participant must file a new Participation Agreement.

4.2 Minimum and Maximum Deferral and Length of Participation. A Participant may elect in a Participation Agreement to defer a portion of Participant's Base Salary or Incentive Compensation. The minimum and maximum amounts that may be deferred under a Participation Agreement shall be as follows:

	Minimum Deferral	Maximum Deferral
With respect to Base Salary Deferrals	2% of Base Salary	100% of Base Salary
With respect to Incentive Compensation	25% of Incentive Compensation	100% of Incentive Compensation

(a) With respect to Base Salary deferrals, the deferral percentage elected in a Participation Agreement shall be applied to the Participant's Base Salary of the Plan Year to which the Participation Agreement applies. A Participation Agreement shall apply to the Participant's Base Salary payable over a deferral period of one Plan Year.

Deferrals shall commence with the Plan Year immediately following the Plan Year in which the respective Participation Agreement is filed; provided, however, that an initial Participation Agreement which is effective other than on January 1 of a Plan Year shall apply to the remainder of the Plan Year.

(b) With respect to Incentive Compensation deferrals, the deferral percentage selected in a Participation Agreement shall apply to the Participant's Incentive Compensation to be earned in the Plan Year immediately following receipt of the Participation Agreement.

(c) A Participant's election to defer Compensation shall be irrevocable upon the filing of the respective Participation Agreement; provided, however, that the deferral of Compensation under any Participation Agreement may be suspended or amended as provided in paragraphs 7.5 and 9.1.

4.3 Subsequent Participation Agreements. In order to participate in any subsequent Plan Year, a Participant must file a new Participation Agreement for that subsequent Plan Year prior to December 15 of the previous calendar year, stating the amount that the Participant elects to have deferred. The new agreement shall be effective only as to Compensation paid in that subsequent Plan Year. A new Participation Agreement is subject to all of the provisions and requirements set forth in paragraph 4.2.

ARTICLE V

Deferred Compensation

5.1 Elective Deferred Compensation. The amount of Compensation that a Participant elects to defer in a Participation Agreement executed by the Participant with respect to each Plan Year of participation in the Plan shall be credited by the Company to the Participant's Deferred Benefit Account throughout each Plan Year as the Participant is paid the non-deferred portion of Compensation for such Plan Year. The amount credited to a Participant's Deferred Benefit Account shall equal the amount deferred. To the extent that the Company is required to withhold any taxes or other amounts from an employee's deferred wages pursuant to any state, federal, or local law, such amounts shall be taken out of the Participant's Compensation which is not deferred under this Plan.

5.2 Effect on Other Plans. To the extent to which deferrals by a Participant under this Plan cause a reduction in pension benefits for a Participant under The Kansas Power and Light Company Retirement Plan or Retirement Plan for Employees of Kansas Gas and Electric Company, the Company shall provide supplementary benefits to the extent of such reduction. The amount of such reduction shall be determined, as of the time of the Participant's retirement under said Retirement Plan, by said Retirement Plan's actuary based upon the form of pension benefit applicable to such Participant, which determination shall be binding and conclusive on such Participant.

To the extent to which deferrals by a Participant under this Plan cause a reduction in the Company matching contributions made by the Company on behalf of the Participant under The Kansas Power and Light Company

Employees' Savings Plan or Kansas Gas and Electric Company 401(K) Plan, the Company shall credit the amount of any such reduction to the Participant's Deferred Benefit Account under the Plan, such amount to be credited quarterly in the year in which such reduction of contributions occurs, based on the Participant's eligible Company match under such savings plan, not to exceed the maximum contribution by the Company under such plans.

The Company shall compute life insurance and disability benefits under any Company plan based on Compensation without reduction for amounts deferred under this Plan.

5.3 Vesting of Deferred Benefit Account. A Participant shall be 100% vested in the Participant's Deferred Benefit Account.

ARTICLE VI

Deferred Benefit Account

6.1 Determination of Account. Each Participant's Deferred Benefit Account as of each Determination Date shall consist of the balance of the Participant's Deferred Benefit Account as of the immediately preceding Determination Date, plus the Participant's elective deferred Compensation withheld since the immediately preceding Determination Date pursuant to paragraph 5.1. The Deferred Benefit Account of each Participant shall be reduced by the amount of all distributions, if any, made from such Deferred Benefit Account since the preceding Determination Date.

6.2 Crediting of Account. As of each Determination Date, the Participant's Deferred Benefit Account shall be increased by the amount of interest earned since the preceding Determination Date. Interest shall be based on the Declared Rate as defined in paragraph 2.5 or as determined under paragraph 7.6(a)(2), as applicable. Interest shall be credited on the average of the balances of the Deferred Benefit Account on the Determination Date and on the last preceding Determination Date, but after the Deferred Benefit Account has been adjusted for any contributions or distributions to be credited or deducted for each such day. Interest will also accumulate on the unpaid balance during any payout period in which a participant is receiving monthly payments.

6.3 Statement of Accounts. The Company shall submit to each Participant, within 120 days after the close of each Plan Year, a statement in such form as the Company deems desirable, setting forth the balance to the credit of each Participant's Deferred Benefit Account as of the last day of the preceding Plan Year.

ARTICLE VII

Benefits

7.1 Specified Distribution Date. Unless a Participant elects to receive benefits under paragraph 7.2 or 7.3 below, on the specified distribution date selected by the Participant in a Participation Agreement, the Participant shall be entitled to a Deferral Benefit equal to the amount of Participant's Deferred Benefit Account determined under paragraphs 6.1 and 6.2 hereof as of the Determination Date coincidental with or immediately following such specified date.

7.2 Retirement or Termination of Employment. Subject to paragraphs 7.1 and 7.6, upon a Participant's Retirement Date, or any termination of employment for reasons other than death or disability, the Participant shall be entitled to a Deferral Benefit equal to the amount of Participant's Deferred Benefit Account determined under paragraphs 6.1 and 6.2 hereof as of the Determination Date coincidental with or immediately following such event.

7.3 Death. Upon the death of a Participant, such Participant's Beneficiary shall receive a Deferral Benefit equal to the remaining balance in such Participant's Deferred Benefit Account.

The Deferral Benefit shall be payable as provided for in paragraph 7.6.

The Deferral Benefit provided above shall be in lieu of all other benefits under this Plan.

7.4 Disability. In the event of Disability, as defined in paragraph 2.10, while employed by the Company, the disabled Participant shall be allocated the amount in Participant's Deferred Benefit Account determined under paragraphs 6.1 and 6.2 as of the Determination Date next following such Disability.

Payments shall commence upon attainment of the Participant's Retirement Date in the form specified in paragraph 7.6(a)(2) over a period from 2 to 360 months. Before payments commence under the preceding sentence, a Disabled Participant may elect, subject to Deferred Compensation Committee approval (Human Resources Committee approval if the Participant is an officer of the Company) upon good cause shown: (i) to accelerate commencement of the payments until the date not earlier than 60 days after the onset of Disability, and/or (ii) to change the form of payment to another form permitted under paragraph 7.6(a).

7.5 Suspension of Participation/Distribution/Failure to Continue Participation. The Deferred Compensation Committee (Human Resources Committee if the Participant is an officer of the Company), in its sole discretion, may suspend the deferral of a Participant's Base Salary during a Plan Year, or authorize a distribution from the Participant's Deferred Benefit Account, upon the advance written request of a Participant on account of financial hardship suffered by that Participant. A Participant must file any request for such suspension or distribution on or before the 15th day preceding the regular pay day on which the suspension or distribution is to take effect. Incentive Compensation deferrals may not be suspended during the Plan Year.

Financial hardship shall mean an unexpected need for cash resulting from conditions in the nature of any of the following:

(a) An accident, illness, or disability suffered by a Participant or a family member or dependent;

(b) A casualty or the theft loss suffered by a Participant of a family member or dependent;

(c) The rendering of a judgment against a Participant or a family member or dependent; or

(d) A sudden financial reversal or curtailment of income experienced by a Participant or a family member or dependent.

The suspension of any deferrals under this paragraph shall not affect amounts deferred with respect to periods prior to the effective date of the suspension.

In the event the Participant ceases to remain a member of the class of employees who are eligible to participate in the Plan, the Participant may elect to suspend the amount of any remaining deferral commitment in this same manner as described for other suspensions in the paragraph, except that committee approval shall not be required.

7.6 Form of Benefit Payment.

(a) Upon retirement, death, a specified distribution date, or termination of employment, the Company shall pay to the Participant or Participant's Beneficiary the balance in the Participant's

Deferred Benefit Account in one of the following forms, as elected in the Participation Agreement filed by the Participant:

(1) A lump sum payment.

(2) A monthly payment of a fixed amount which shall amortize the Deferred Benefit Account balance in equal monthly payments of principal and interest over a period from 2 to 360 months. For purposes of determining the amount of the monthly payment, the rate of interest shall be the average of the Declared Rate for the shorter of (i) the last five (5) Plan Years preceding the initial monthly installment payment, or (ii) the actual number of Plan Years of participation by the Participant.

(b) In the absence of a Participant's election under subparagraph 7.6(a), benefits shall be paid in the form specified in subparagraph 7.6(a)(2) over a 180 month period. In the event of a Disabled Participant, payment shall be in the form described in paragraph 7.4.

7.7 Withholding: Payroll Taxes. To the extent required by law in effect at the time payments are made, the Company shall withhold from payments made hereunder any taxes required to be withheld from any employee's wages for the federal or any state or local government.

7.8 Commencement of Payments. Commencement of payments under this Plan shall begin within sixty days following receipt of notice by the Deferred Compensation Committee in the event of death, retirement, or termination of employment which entitles a Participant (or a Beneficiary) to payments under this Plan. All payments shall be made as of the first day of the month.

If a Participant receives benefits hereunder because of retirement, payments will commence coincident with the payment of benefits to the Participant under The Kansas Power and Light Company Retirement Plan or the Retirement Plan for Employees of Kansas Gas and Electric Company.

A Participant must elect to receive benefits under each Participation Agreement upon either i) a specified distribution date, or ii) retirement or termination of employment.

Subject to paragraph 7.3 in the event a Participant elects to receive benefits upon a specified distribution date, payments will commence upon the first business day of the year specified.

ARTICLE VIII

Beneficiary Designation

8.1 Beneficiary Designation. Each Participant shall have the right, at any time, to designate any person or persons as Beneficiary or Beneficiaries (both principal as well as contingent) to whom payment under this Plan shall be made in the event of Participant's death prior to complete distribution of the benefits due to the Participant under the Plan.

8.2 Amendments. Any Beneficiary designation may be changed by a Participant by the written filing of such change on a form prescribed by the Deferred Compensation Committee. The filing of a new Beneficiary Designation form will cancel all Beneficiary designations previously filed.

8.3 No Beneficiary Designation. If a Participant fails to designate a Beneficiary as provided above, or if all designated Beneficiaries predecease the participant, then the Participant's designated Beneficiary shall be deemed to be the person or persons surviving Participant in the first of the following classes in which there is a survivor, share and share alike:

(a) The surviving Spouse;

(b) The Participant's children, except that if any of the children predecease the Participant but leave issue surviving, then such issue shall take by right of representation the share their parent would have taken if living;

(c) The Participant's personal representative (executor or administrator).

8.4 Effect of Payment. The payment to the deemed Beneficiary shall completely discharge the Company's obligations under this Plan.

ARTICLE IX

Amendment and Termination of Plan

9.1 Amendment. The Board may at any time amend the Plan in whole or in part; provided, however, that no amendment shall be effective to decrease or restrict any Deferred Benefit Account at the time of such amendment or reduce any additional benefits provided under paragraph 5.2. In the event the Plan is amended, a Participation Agreement shall be subject to the provisions of such amendment as if set forth in full therein, without further action or amendment to the Participation Agreement. The parties shall be bound by, and have the benefit of, each and every provision of the Plan, as amended from time to time.

9.2 Company's Right to Terminate. The Board may at any time terminate the Plan with respect to new elections to defer if, in its judgment, the continuance of the Plan, the tax, accounting, or other effects thereof, or potential payments thereunder would not be in the best interests of the Company. The Board may also terminate the Plan in its entirety at any time, and upon any such termination, all Participants under the Plan shall be paid the balance in their Deferred Benefit Accounts in a lump sum, or over such period of time as determined by the Board.

9.3 Premature Plan Terminations and Premature Distributions. The Deferred Compensation Committee shall have the right (but shall not be obligated) to require premature Plan termination and premature Plan distributions to Participants, upon the occurrence of any of the following conditions or events:

(a) If any rating on any debt securities of the Company, as rated by Moody's or Standard & Poor's, is downgraded to a rating lower than that rating as of the date of this Plan;

(b) If the shareholders of the Company approve the merger or consolidation of the Company with or into any other corporation (other than a corporation wholly-owned by the Company immediately prior to such event) or the acquisition of substantially all of the business or assets of the Company by any other person or entity (other than a corporation wholly-owned by the Company immediately prior to such event);

(c) If a change occurs in the Board of Directors of the Company whereby Directors comprising a majority of the Board of Directors immediately prior to such change do not continue to comprise such a majority immediately after such change, provided that incremental and/or related changes (including but not limited to resignations from the Board of Directors) which occur within a relatively brief period of time shall be considered to be but a single change for purposes of this Subparagraph;

(d) If, as a result of any tender offer or otherwise, any person or entity or affiliated group becomes the beneficial or record owner of more than 10% of the outstanding voting securities of the Company; or

(e) If, in the Deferred Compensation Committee's sole judgment and discretion, a change in circumstances has occurred (including but not limited to a change in taxation laws or regulations, securities laws or regulations, accounting requirements or the events in Subparagraphs (a), (b), (c), and (d) of this Paragraph 9.3) which causes the Plan to be undesirable to a significant portion of the Participants.

ARTICLE X

Miscellaneous

10.1 Unsecured General Creditor. Participants and their Beneficiaries shall have no legal or equitable rights, interest, or claims in any property or assets of the Company, nor shall they be Beneficiaries of, or have any rights, claims, or interests in any life insurance policies, annuity contracts, or the proceeds therefrom owned or which may be acquired by the Company ("Policies"). Such Policies or other assets of the Company shall not be held under any trust for the benefit of Participants or their Beneficiaries or held in any way as collateral security for the fulfilling of the obligations of the Company under this Plan. Any and all of the Company's assets and Policies shall be, and remain, the general, unpledged, and unrestricted assets of the Company. The Company's obligation under the Plan shall be merely that of an unfunded and unsecured promise of the Company to pay money in the future.

10.2 Non-assignability. Neither a Participant nor any other person shall have any right to commute, sell, assign, transfer, pledge, anticipate, mortgage, or otherwise encumber, transfer, hypothecate, or convey in advance of actual receipt the amounts, if any, payable hereunder, or any part thereof, which are, and all rights to which are, expressly declared to be unassignable and non-transferable. No part of the amounts payable shall, prior to actual payment, be subject to seizure or sequestration for the payment of any debts, judgments, alimony, or separate maintenance owed by a Participant or any other person, nor be transferable by operation of law in the event of a Participant's or any other person's bankruptcy or insolvency.

10.3 Not a Contract of Employment. The terms and conditions of this Plan shall not be deemed to constitute a contract of employment between the Company and the Participant, and the Participant (or Participant's Beneficiary) shall have no rights against the Company except as may otherwise be specifically provided herein. Moreover, nothing in this Plan shall be deemed to give a Participant the right to be retained in the service of the Company or to interfere with the right of the Company to discipline or discharge Participant at any time.

10.4 Protective Provisions. A Participant (or Participant's Beneficiary) will cooperate with the Company by furnishing any and all information requested by the Company in order to facilitate the payment of benefits hereunder, by taking such physical examinations as the Company may deem necessary, and by taking such other action as may be requested by the Company.

10.5 Governing Law. The provisions of this Plan shall be construed and interpreted according to the laws of the State of Kansas.

10.6 Successors. The provisions of this Plan shall bind and inure to the benefit of the Company and its successors and assigns.

10.7 Effective Date. This Plan shall become effective as of October 15, 1993.

10.8 Incompetent. In the event that it shall be found upon evidence satisfactory to the Deferred Compensation Committee that any Participant or Beneficiary to whom a benefit is payable under this Plan is unable to care for such Participant's or such Beneficiary's affairs because of illness or accident, any payment due (unless prior claim therefor shall have been made by a duly authorized guardian or other legal representative) may be paid, upon appropriate indemnification of the Company, to the Spouse or other person deemed by the

Committee to have incurred any expense for such Participant or a Beneficiary. Any such payment shall be a payment for the account of the Participant or a Beneficiary and shall be a complete discharge of any liability of the Company therefor.

WESTERN RESOURCES DEFERRED COMPENSATION PLAN
PARTICIPATION AGREEMENT

This Agreement is made and entered into as of this _______ day of ______________________________, 19_______, by and between Western Resources, Inc. (the "Company") and ____ (a "Participant") and shall be effective beginning with the _______ day of ______________________________, 19_______ ("Effective Date").

WHEREAS, the Company has adopted the Western Resources Deferred Compensation Plan (the "Plan"); and,

WHEREAS, the Plan requires that an Agreement be entered into between the Company and the Participant,

NOW, THEREFORE, the Company and the Participant hereby agree as follows:

1. Plan. The Plan, a copy of which has been provided to Participant, is hereby incorporated into and made a part of this Agreement as though set forth in full herein. The parties shall be bound by, and have the benefit of, each and every provision of the Plan. By executing this Agreement, the Participant acknowledges receipt of a copy of the Plan and confirms understanding and acceptance of all of the terms, provisions, and conditions thereof.

2. Deferral Election.

   Base Salary Deferral (for Plan Year 1993)

   _____ a) Participant hereby elects to defer an amount equal to _______% (from 2% to 100%) of Base Salary to be earned by Participant in the remainder of Plan Year 1993.

   _____ b) Participant is not electing Base Salary Deferral for the remainder of Plan Year 1993.

   Base Salary Deferral (for Plan Year 1994)

   _____ a) Participant hereby elects to defer an amount equal to _______% (from 2% to 100%) of Base Salary to be earned by Participant in Plan Year 1994.

   _____ b) Participant is not electing Base Salary Deferral for Plan Year 1994.

   Incentive Compensation Deferral (for Plan Year 1994)

   _____ a) The Participant elects to defer receipt of _______% (from 25% to 100%) of Incentive Compensation to be earned by Participant in Plan Year 1994 and payable in 1995.

   _____ b) Participant is not electing Incentive Compensation Deferral in this Agreement.

NOTE: All percentages and resulting dollar amounts will be rounded to the nearest whole percentage or dollar.

3. Payment of Benefits - Death Before Retirement or Specified Distribution Date

   Form of Benefit Payment

   _____ a) Not applicable (mark if paragraph 4c or 4g is not selected).

   _____ b) A lump sum payment.

   _____ c) Level monthly installment payments for _______ months as provided in paragraph

7.6(a)(2) [specify a period not less than 2 nor more than 360 months].

NOTE: Complete either paragraph 4 or both paragraphs 5 and 6. Do not complete all three paragraphs.

4. Payment of Benefits - Specified Distribution Date; Death Before Specified Distribution Date

Form of Benefit Payment (Base Salary)

_____ a) A lump sum payment.

_____ b) Level monthly installment payments for _______ months as provided in paragraph 7.6(a)(2) [specify a period not less than 2 nor more than 360 months].

_____ c) I elect to receive benefits upon death should death occur prior to the specified distribution date. (complete paragraph 3)

_____ d) Specified Distribution Date -- (specify a year when distributions are to commence on the first business day of such year).

Form of Benefit Payment (Incentive Compensation)

_____ e) A lump sum payment.

_____ f) Level monthly installment payments for _______ months as provided in paragraph 7.6(a)(2) [specify a period not less than 2 nor more than 360 months].

_____ g) I elect to receive benefits upon death should death occur prior to the specified distribution date. (complete paragraph 3)

_____ h) Specified Distribution Date -- (specify a year when distributions are to commence on the first business day of such year).

5. Payment of Benefits - Termination Other Than Death

Form of Benefit Payment (Base Salary)

_____ a) A lump sum payment.

_____ b) Level monthly installment payments for _______ months as provided in paragraph 7.6(a)(2) [specify a period not less than 2 nor more than 360 months].

Form of Benefit Payment (Incentive Compensation)

_____ c) A lump sum payment.

_____ d) Level monthly installment payments for _______ months as provided in paragraph 7.6(a)(2) [specify a period not less than 2 nor more than 360 months].

6. Payment of Benefits - Retirement Date

Form of Benefit Payment (Base Salary)

_____ a) A lump sum payment.

_____ b) Level monthly installment payments for _______ months as provided in paragraph 7.6(a)(2) [specify a period not less than 2 nor more than 360 months].

Form of Benefit Payment (Incentive Compensation)

_____ c) A lump sum payment.

_____ d) Level monthly installment payments for _______ months as provided in paragraph 7.6(a)(2) [specify a period not less than 2 nor more than 360 months].

7. Amendments. All subsequent amendments to the Plan shall also be incorporated into and made a part of this Agreement as though set forth in full herein, without further action or amendments to this Agreement. The parties shall be bound by, and have the benefit of, each and every provision of the Plan, as amended from time to time.

8. Binding Effect. This Agreement shall inure to the benefit of, and be binding upon the Company, its successors and assigns, and the Participant and Participant's Beneficiaries.

IN WITNESS WHEREOF, the parties hereto have signed and entered into this Agreement on and as of the date first above written.

____
Participant's Signature

WESTERN RESOURCES, INC.

By____

Title____

WESTERN RESOURCES DEFERRED COMPENSATION PLAN
BENEFICIARY DESIGNATION

Name in full____SS#________________

I designate the following as Beneficiary or Beneficiaries to receive, in accordance with the method indicated, any payments to which my Beneficiary or Beneficiaries may be entitled under the Western Resources Deferred Compensation Plan (Paragraph 2.1 and Article VIII) in the event of my death either prior to or after my retirement, subject to my right at any time to change such Beneficiary or Beneficiaries as provided under the Plan.

Beneficiaries	Name	Relationship	Share of Payment (%)
Primary______	______	______	______
Primary______	______	______	______
Contingent______	______	______	______
Contingent______	______	______	______
Contingent______	______	______	______
Contingent______	______	______	______

This beneficiary designation or change supersedes all previous designations or changes made by me under the Plan.

____
Participant's Signature   Date

____
Committee Acknowledgement   Date

WESTERN RESOURCES
DEFERRED COMPENSATION PLAN

1. What is the purpose of the Plan?

The purpose of the Plan is to give you the opportunity to supplement your estate planning and accumulate tax deferred income by deferring all or a portion of your pre-tax base salary and/or incentive compensation, which is then credited with interest on a tax-deferred basis. This will allow you to supplement your standard of living at retirement.

2. Why is the Deferred Compensation Plan important to me?

It lets you delay the payment of income taxes on all or a portion of your income, by having Western Resources retain it and pay it to you at a later date. The amounts which you defer will earn tax-deferred interest.

3. Who can participate in this Plan?

The Deferred Compensation Plan is available only to Eligible Key Management Employees, as designated by the Human Resources Committee of the Board of Western Resources.

You may elect to participate in the Plan in addition to all other Western Resources benefit plans for which you are currently eligible.

4. How much can I defer?

Your participation in the Plan is based on deferral of all or a portion of your base salary and/or incentive cash compensation for a period of one year. Upon enrolling in the Plan, you will specify in a Participation Agreement the amount of your deferral. The minimum annual deferral is 2% of base salary, and/or 25% of incentive compensation.

5. May I suspend my deferral commitments or receive a distribution from my Deferred Benefit Account in the event of financial hardship?

The Deferred Compensation Committee may, in its sole discretion and upon your written request, suspend the deferral of your salary that would otherwise occur under a Participation Agreement and/or authorize a distribution from your Deferred Benefit Account if you have suffered a financial hardship. The suspension will take effect only with respect to salary deferrals which have not already occurred.

6. What are examples of financial hardship?

Financial hardship means an unexpected need for cash resulting from an occurrence in the nature of any of the following:

a) An accident, illness, or disability suffered by you or a family member or dependent;

b) A casualty or theft loss suffered by you or a family member or dependent;

c) The rendering of a judgment against you or a family member or dependent; or

d) A sudden financial reversal or curtailment of income experienced by you or a family member or dependent.

7. How much interest is credited on the Deferred Benefit Account?

The interest credited to your Deferred Benefit Account will be based on Western Resources long term cost of capital, and established annually by the Human Resources Committee of the Board. The interest on deferred amounts will change annually. The rate for the balance of Plan Year 1993 and for Plan Year 1994 will be 10.01% APR.

8. How will benefits be paid?

Generally, benefits may be paid in a lump sum or in equal monthly installments consisting of principal and interest at the Plan Credit Rate up to 360 months. You elect the form in which payments are to be made. If you fail to elect a form of payment, you will receive your benefit payments in installments over a 180 month period.

9. What happens upon my retirement?

Unless you designate a specific distribution date, upon your election to retire under either the Retirement Plan for Employees of Kansas Gas and Electric Company or The Kansas Power and Light Company Retirement Plan, you will receive benefits commencing within 60 days after the Committee is notified of your retirement. Your benefit will be based on your Deferred Benefit Account balance at that time. In the event the Account balance is paid out over a number of months, interest will be paid on the unpaid balance based on the Plan Credit Rate.

10. What happens to my account in the event of death?

You will designate a beneficiary to receive benefits under the Plan and will have the right to change the beneficiary designation from time to time by completing a beneficiary designation change form.

If your death should occur before retirement, your beneficiary will be paid your Deferred Benefit Account balance either as a lump sum or paid monthly (up to 360 months) depending upon your election.

In the event of your death after deferral benefits have started, your beneficiary will continue to receive installments until the balance of your account has been paid. Interest will continue to accrue on your Deferred Benefit Account at the Plan Credit Rate during the period of distribution.

11. What if I become disabled?

If disability occurs while employed by Western Resources and you would qualify for long term disability benefits according to the terms of the Long Term Disability Plan maintained by Western Resources, payments from your Deferred Benefit Account will commence, subject to Committee approval, no earlier than 60 days after the onset of your disability.

12. What happens if employment is terminated before I am eligible for Retirement?

Unless you designate a specific distribution date, in the event of termination of employment for reasons other than death, retirement, or disability, your Deferred Benefit Account balance will be payable either as a lump sum or paid monthly (up to 360 months). In the event the Account balance is paid out over a number of months, interest will be paid on the unpaid balance based on the Plan Credit Rate.

13. How is the Plan administered?

The Plan is administered by the Human Resources Committee of the Board and the Deferred Compensation Committee. The Committees will resolve all questions involving interpretations of the Plan.

14. Is my Deferred Compensation held in Trust?

No. Benefits payable under the Plan depend upon and will be paid exclusively from the general assets of Western Resources. Western Resources' liability, for the payment of benefits under the Plan, will be unsecured and unfunded, as evidenced by the terms of the Plan and the current Participation Agreement between you and the Company.

15. How does participation in the Plan affect my other Western Resources benefits?

When you participate in the Plan, you are required to defer current compensation. This may affect your benefits under other Western Resources plans, which are based upon your compensation. The following are the main effects of which you should be aware:

a) Life insurance and disability benefits will be based on your compensation without reduction for any amounts deferred under this Plan.

b) To the extent to which your deferrals cause a reduction in pension benefits under either the KP&L or KG&E retirement plans, Western Resources will provide you with supplementary benefits to the extent of such reduction.

   These supplemental benefits, like the Deferred Compensation benefits are unfunded and represent an unsecured general obligation of the Company.

c) To the extent to which your deferrals cause a reduction in the Company matching contributions under either the KP&L or KG&E 401 (K) plans, Western Resources will credit the amount of any such reduction to your Deferred Benefit Account on December 31 of the year in which such reduction of contribution occurs, based on your eligible Company matching contribution, not to exceed the maximum company contribution provided in the 401(k) plan.

16. When is the Deferred Compensation Plan effective?

The Plan will become effective October 15, 1993, when the enrollment process has been completed and the Participation Agreement has been signed by both you and Western Resources. The enrollment process includes completion of:

a) Participation Agreement

b) Beneficiary Designation Form

c) Worksheet

WESTERN RESOURCES, INC.
LONG-TERM INCENTIVE PROGRAM

The purpose of the Western Resources, Inc. Long Term Incentive Program is to provide a select group of management and executive employees of the Company with incentives to work for the long-range growth of the Company and to provide a competitive means by which management and executive employees with superior capabilities may be attracted to and retained by the Company.

1. Definitions. As used herein the following words and phrases shall have the following respective meanings unless the context clearly indicates otherwise:

(a) Account: The account established by the Company for the Participant for each Incentive Period. The Account shall be credited upon an Award to the Participant, and debited upon distribution or cancellation of an Award.

(b) Award: A grant of Performance Shares made to a Participant's Account under the terms of the Program.

(c) Beneficiary: The person or persons designated by a Participant pursuant to Section 9 to receive any distribution which under the terms and conditions of the Program may be made on behalf of the Participant after the Participant's death.

(d) Board of Directors: The Board of Directors of the Company.

(e) Committee: The committee which may be established by the Board of Directors pursuant to section 2 to administer the Program.

(f) Common Stock: The Company's common stock, par value $5.00 per share.

(g) Company: Western Resources, Inc. a Kansas corporation, and its successors and assigns.

(h) Incentive Period: A three year period at the beginning of which an Award is made to Participants' Accounts and at the end of which a determination is made whether or not the Performance Standard has been obtained. Each January 1 a new Incentive Period shall commence. The first Incentive Period shall be January 1, 1991 through December 31, 1993.

(i) Market Value: The average of the high and low prices for the Common Stock reported by the New York Stock Exchange (NYSE) on the date or dates specified in the Program (or, if such date shall not be a NYSE business day, the next succeeding day which shall be a business day).

(j) Participant: An employee to whom an Award has been made which has not been paid, canceled, or otherwise terminated or satisfied under the terms of the Program.

(k) Performance Share: The unit of measurement for Awards under the Program which, at any given time, shall be equal in value to the current Market Value of one share of Common Stock.

(l) Performance Standards: The standards described in Section 5 relating to each Incentive Period, the satisfaction of which shall determine the Participant's entitlement to a Stock Distribution.

(m) Program: The program herein set forth, as from time to time amended.

(n) Stock Distribution: The common stock to which a Participant is entitled to receive at the end of any Incentive Period, as determined in accordance with Sections 5 and 6.

2. Administration. The entire Board of Directors, or if

one shall be appointed by the Board of Directors, a committee of at least three directors, all of whom are not eligible to be Participants (the "Committee"), shall be responsible for administering, construing and interpreting the Program. The interpretation and construction by the Board of Directors, or the Committee if one shall be appointed, of any provision of the Program shall be final and conclusive.

The day-to-day administration of the Program shall be carried out by such employees of the Company as shall be designated from time to time by the Board of Directors, or the Committee if one shall be appointed.

The members of the Board of Directors, the members of the Committee, and all agents, officers, fiduciaries and employees of the Company shall not be liable for any act, omission, interpretation, construction or determination made in good faith in connection with their responsibilities with respect to the Program; and the Company hereby agrees to indemnify the members of the Board of Directors, the members of the Committee, and all agents, officers, fiduciaries, and employees of the Company in respect of any claim, loss, damage or expense (including counsel fees) arising from any such act, omission, interpretation, construction or determination to the full extent permitted by law.

3. Eligibility to Participate. Only those employees who are members of the President's Council shall automatically be eligible to participate in the Program. Such participation shall commence with the first Incentive Period. The Board of Directors, or the Committee if one shall be appointed, shall determine, from time to time, whether members of the Senior Management Council and employees in Pay Grades 30 and above shall be eligible to participate with respect to any subsequent Incentive Period.

4. General Terms and Conditions of Awards.

(a) Performance Share Grants. At the beginning of the first year of each Incentive Period, an Award of Performance Shares shall be made to each Participant's Account. The number of Performance Shares to be awarded to each Participant's Account shall equal the number of shares of Common Stock having a Market Value on January 2 of such year equal to 10 percent of the Participant's base annual compensation determined as of January 1 of the first year of the Incentive Period. Except with respect to the dividend equivalent distributions to be made pursuant to Section 4(b), Participants shall not receive any payment with respect to the Performance Shares until the accomplishment of the Performance Standard in accordance with Section 5.

(b) Distributions. In the event the Company pays any dividends or makes any other distributions with respect to its Common Stock in cash or in property, including securities (other than a dividend or distribution of shares of Common Stock), each Participant shall be entitled to receive in cash at the same time as such dividend is paid or other distribution is made to the stockholders, an amount equal to the value of such dividend or other distribution determined as if the Participant were the holder of the number of shares of Common Stock equal to the number of Performance Shares in his or her account. The value of such distribution, if other than cash, shall be determined by the Board of Directors, or the Committee if one shall be appointed, and such determination shall be conclusive.

(c) Changes in Capitalization. In the event of a stock dividend, stock split, recapitalization, reorganization, merger, consolidation, split-up, or any similar change affecting the Common Stock while any Performance Shares are outstanding, the Board of Directors, or the Committee if one shall be appointed, shall make such adjustments in the number of Performance Shares in each Participant's Account as shall, in the sole judgment of the Board of Directors or the Committee, as appropriate, be equitable and appropriate in order to make such Account, as nearly as practicable, equivalent to the value of the Performance Shares in the Account immediately prior to such change.

5. Performance Standards. The Performance Standards establish certain corporate goals to be attained during each Incentive Period in order for a Participant to receive a Stock

Distribution. A Participant's right to a Stock Distribution, and the amount thereof, shall be determined by the Distribution Percentage.

(a) Distribution Percentage. The Distribution Percentage shall consist of two weighted elements, the Financial Criteria Percentage and the Performance Criteria percentage. The sum of the weighted Financial Criteria Percentage and the weighted Performance Criteria percentage shall equal the Distribution Percentage. The following formula shall be used: (Financial Criteria Percentage X 70%) + (Performance Criteria Percentage X 30%) = Distribution Percentage.

(1) Financial Criteria Percentage. By May 31, 1991 for the first Incentive Period, and as early as practical each succeeding Incentive Period, the Board of Directors, or the Committee if one shall be appointed, shall establish for the Incentive Period certain annual financial goals. Promptly following the end of each Incentive Period, the Board of Directors, or the Committee if one shall be appointed, shall determine the Financial Criteria Percentage over the Incentive Period.

(2) Performance Criteria Percentage. The Performance Criteria Percentage is derived by evaluating the performance of the Company and the Participants. The Performance Criteria for each Incentive Period, which shall consist of the long-range strategic goals, objectives, and planned targets for the Company and the Participants, shall be established at the beginning of the respective Incentive Period. The Board of Directors, of the Committee if one shall be appointed, without the participation of the Chief Executive Officer of the Company (the "CEO"), shall determine and set forth in writing the Performance Criteria for the CEO. The CEO shall set forth in writing the Performance Criteria for the members of the President's Council other than the CEO. The President's Council shall set forth in writing the Performance Criteria for all other Participants. At the end of each Incentive Period, the Board of Directors, without the participation of the CEO, shall determine the percentage of Performance Criteria achieved by the CEO. The percentage of Performance Criteria achieved by the members of the President's Council other than the CEO shall be determined by the CEO. The percentage of Performance Criteria achieved by the remaining Participants shall be determined by the President's Council. The percentage of Performance Criteria achieved shall be called the "Performance Criteria Percentage."

(b) Earned Performance Shares. The actual number of Performance Shares earned by the Participant shall be determined by reference to the Actual Distribution Percentage determined by the Board of Directors. Such percentage shall not exceed 110%.

The Actual Distribution Percentage shall be multiplied by the number of Performance Shares in the Participant's Account for the Incentive Period, and the product shall be the number of Earned Performance Shares upon which the Participant's Stock Distribution shall be based. If the Actual Distribution Percentage is greater than 100%, the Participant shall have more Earned Performance Shares than are credited to his or her Account.

6. Distribution of Awards.

(a) Generally. The Participant shall be entitled to receive one share of Common Stock for each Earned Performance Share determined in accordance with Section 5(b) (the "Stock Distribution"). All Stock Distributions shall be made within 60 days of the last day of the appropriate Incentive Period. Partial Earned Performance Shares shall be distributed in cash and shall equal the Market Value of one share of Common Stock as of the last day of the

Incentive Period multiplied by the fraction of the Earned Performance Share.

(b) Termination of Employment. A Participant who ceases to be continually employed by the Company throughout the Incentive Period (other than as a result of a Company-approved leave of absence or the Participant's death, disability, or retirement under the Company pension plan's early or normal retirement provisions), shall forfeit all rights to any allocated Performance Shares and any Stock Distribution for such Incentive Period.

(c) Payment in the Event of Death, Disability or Retirement. If a Participant dies, becomes disabled or retires under the Company pension plan's early or normal retirement provisions during any Incentive Period, the Participant (or the appointed Beneficiaries in the case of death) shall receive any payment to which the Participant would otherwise have been entitled had he or she been employed on the last day of the Incentive Period, including the distributions provided for in Section 4(b). All payments, including the Stock Distribution, shall be made to the Participant (or the Participant's Beneficiary) at the time and in the manner that such payment and stock distribution would have been made to the Participant had he or she remained employed.

7. Change in Control. Notwithstanding any contrary provisions of this Program or any instruments evidencing Awards granted hereunder, in the case of a Change in Control of the Company, each Participant shall immediately become fully vested in and be entitled to receive, a Stock Distribution in an amount equal to the number of the Performance Shares allocated to his or her Account. Such Stock Distribution shall be made to Participants as soon as practicable. A Change in Control shall occur if:

(a) any "person" or group of persons" (as such terms are used in sections 13(d) and 14(d) of the Securities Exchange Act of 1934) other than pursuant to a transaction or agreement previously approved by the Board of Directors, directly or indirectly purchases or otherwise becomes the "beneficial owner" (as defined in Rule 13d-3 under the Securities Exchange Act of 1934) or has the right to acquire such beneficial ownership (whether or not such right is exercisable immediately, with the passage of time, or subject to any condition), of voting securities representing 20% or more of the combined voting power of all outstanding voting securities of the Company;

(b) during any period of 24 consecutive calendar months, the individuals who at the beginning of such period constitute the Company's Board of Directors, and any new directors whose election by such Board of nomination for election by stockholders was approved by a vote of at least two-thirds of the members of such Board who were either directors on such Board at the beginning of the period or whose election or nomination for election as directors was previously so approved, for any reason cease to constitute at least a majority of the members thereof;

(c) the Company adopts any plan of liquidation providing for the distribution of all or substantially all of its assets;

(d) all or substantially all of the business of the Company is disposed of pursuant to a merger, consolidation or other transaction in which the Company is not the surviving Company or is substantially or completely liquidated (unless the shareholders of the Company immediately prior to such merger, consolidation or other transaction beneficially own, directly or indirectly, in substantially the same proportion as they owned the voting stock of the Company, all of the voting stock or other ownership interests of the entity or entities, if any, that succeed to the business of the Company);

(e) the Company enters into a contract to sell 50 percent or more of its assets or earning power; or

(f) the Company combines with another company and is the surviving corporation but, immediately after the combination, the shareholders of the Company immediately prior to the combination (other than shareholders who, immediately prior to the combination, were "affiliates" of such other company, as such term is defined in the rules of the Securities and Exchange Commission) do not beneficially own, directly or indirectly, more than 50% of the voting stock of the combined corporation.

If a Change in Control shall occur by reason of any of the events described in (c) through (f) above, the Awards which shall become vested and non-forfeitable shall be distributed to Participants immediately prior to such Change in Control.

8. Withholding for Taxes. The Company will provide for the withholding of any taxes required by any governmental authority with respect to any payment that is to be made under the Program. The amount withheld shall be paid over by the Company to such governmental authority for the account of the Participant entitled to the payment.

9. Designation of Beneficiary. A Participant shall designate a Beneficiary or Beneficiaries on the Beneficiary Designation form in the appendix (which may be designated contingently and which may be an entity other than a natural person) to receive any amounts which under the terms of the Program may become payable on or after the Participant's death. Any such designation may, unless the Participant has waived such right, from time to time and at any time, be changed or cancelled by the Participant without the consent of a Beneficiary. Any such designation must be in writing and filed with the Board of Directors, or the Committee if one shall be appointed. If a Participant designated more than one Beneficiary, any payments under the Plan to such Beneficiaries shall be made in equal shares unless the Participant has designated otherwise, in which case the payments shall be made in the shares designated by the Participant. If a Participant does not designate a Beneficiary or there is no proper designation of a Beneficiary or no person designated as a Beneficiary shall survive the Participant, the Participant's Beneficiary shall be his or her estate.

10. No Rights to Corporate Assets. Nothing contained herein shall be construed as giving a Participant, his or her Beneficiary or any other person any equity or other interest of any kind in any assets of the Company or creating a trust of any kind or a fiduciary relationship of any kind between the Company and any such person. As to any claim for any unpaid amounts under the Plan, a Participant, his or her Beneficiary and any other person having a claim for payments shall be unsecured creditors.

11. Non-Assignability. Except as provided in Section 9, neither a Participant nor a Participant's Beneficiary shall have the power or right to transfer, assign, anticipate, mortgage or otherwise encumber his or her interest in the Program; nor shall such interest be subject to seizure for the payment of a Participant's or Beneficiary's debts, judgments, alimony, or separate maintenance or be transferable by operation of law in the event of a Participant's or Beneficiary's bankruptcy or insolvency.

The Company's obligations under the Program are not assignable or transferable except to a Company which acquires all or substantially all of the assets of the Company or to any corporation into which the Corporation may be merged or consolidated.

12. Amendment and Termination. The Board of Directors may from time to time and at any time alter, amend, suspend, discontinue or terminate the Program. Nothing contained in the Program shall be construed to prevent the Company from taking any corporate action which is deemed by the Company to be appropriate or in its best interest, whether or not such action would have an adverse effect on the Program or any Participant's interest in the Program. Neither any Participant nor any other person shall have any claim against the Company as a result of any such action. Notwithstanding the foregoing, the Company may not modify (or terminate) the Program to the extent doing so would adversely affect the rights of Participants to Performance Shares in their Accounts at the time of the modification.

13. No Right of Employment. Nothing contained in the Program shall be construed as conferring upon a Participant the right to continue in the employ of the Company.

14. Governing Law. All rights and obligations under the Program shall be governed by, and the Program shall be construed in accordance with the laws of the State of Kansas.

15. Titles and Headings. Titles and headings to sections herein are for purposes of reference only, and shall in no way limit, define or otherwise affect the meaning or interpretation of any provisions of the Program.

16. Effective Date. The Program shall become effective January 1, 1991.

BENEFICIARY DESIGNATION

Pursuant to Section 9 of the Western Resources' Long-Term Incentive Plan, the Participant hereby designates as Primary Beneficiary under this Plan:

____
____

____
____

and, Participant hereby designates as Secondary Beneficiary under this Plan:

____
____

____
____

The term "Beneficiary" as used herein shall mean the Primary Beneficiary if such Primary Beneficiary shall survive Participant by at least 30 days, and shall mean the Secondary Beneficiary if Primary Beneficiary does not survive Participant by at least 30 days, and shall mean the Estate of the Participant, if neither Primary nor Secondary Beneficiary survives the Participant by at least 30 days. Participant shall have the right to change Participant's designation of Primary and/or Secondary Beneficiary from time to time in such manner as shall be required by the Board of Directors or the Committee, it being agreed that no change in beneficiary shall be effective until acknowledged in writing by the Company.

IN WITNESS WHEREOF, Participant has executed this designation this __________ day of _______________________, 19____.

PARTICIPANT:

____
(signature)

____
(type or print name)

WESTERN RESOURCES, INC.
SHORT-TERM INCENTIVE PLAN

The purpose of the Western Resources, Inc. Short-Term Incentive Plan (Plan) is to motivate key executives, directors, managers, and select exempt employees to achieve the highest level of performance to further the achievement of Western Resources' (WR's) goals, objectives, and strategies. This Plan is designed to reward exceptional performance using financial incentives to supplement base compensation. Also, the Plan will enhance the ability of WR to attract new executive talent when needed. Finally, the Plan is intended to benefit WR in the pursuit of its goals and objectives by stimulating and motivating the President's Council (PC), the Senior Management Council (SMC) and select exempt employees, which will in turn enhance productivity and promote the retention of experienced and qualified executive talent in a cost effective and efficient manner.

1. Definitions. As used herein the following words and phrases shall have the following respective meanings unless the context clearly indicates otherwise:

(a) Award: A grant of a percentage of the total incentive award made to a Participant under the terms of the Plan.

(b) Award Criteria: The criteria described in Section 4, consisting of financial, individual, and discretionary criteria, the satisfaction of which shall determine the Participant's percentage entitlement to an Incentive Award.

(c) Beneficiary: The person or persons designated by a Participant pursuant to Section 7 to receive any payment which under the terms and conditions of the Plan may be made on behalf of the Participant on or after the Participant's death.

(d) Board of Directors: The Board of Directors of the Company.

(e) Company: Western Resources, Inc. a Kansas corporation, and its successors and assigns.

(f) Discretionary Criteria: Criteria based solely on the Participant's Supervisor's discretion.

(g) Financial Criteria: Criteria which is based on the overall company profitability as compared to budget.

(h) Incentive Award: That percentage of a Participant's base compensation which the Board of Directors shall, from time to time, determine to be available to a Participant under the Plan. As an example, a PC member may be entitled to earn up to 20% of their base compensation as an Award. The Incentive Award may apply to a class of employees or to individual employees, at the discretion of the Board of Directors or the Committee.

(i) Individual Criteria: Criteria which is based on financial or nonfinancial criteria or both, as determined by the Participant and the Participant's Supervisor.

(j) Individual Agreement: An agreement developed during the strategic and financial planning process at the beginning of each WR fiscal year, which outlines a Participant's participation in the Plan. Goals and objectives critical to the successful implementation of the WR Strategic Plan are the basis for developing the detail components of each Agreement.

(k) Participant: An employee with whom an Individual Agreement has been made, but which has not been paid, canceled, or otherwise terminated or satisfied under the terms of the Plan.

(l) Plan: The Plan herein set forth, and as from time to time amended.

(m) Select Exempt Employees: WR executive employees in pay grades 30 and above.

(n) Participant's Supervisor: The officer, director or manager to whom the Participant directly reports. The CEO's Supervisor shall mean the Board of Directors. A PC member's supervisor is the CEO . A SMC member's supervisor is the member of the PC to whom that member directly reports. A Select Exempt Employee's Supervisor shall be the member of the PC or the SMC to whom that Exempt Employee reports.

(o) Committee: The committee which may be established by the Board of Directors pursuant to Section 2 to administer the Plan.

2. Administration. The Board of Directors, or if one shall be appointed by the Board of Directors, a committee of at least three directors, a majority of whom are not eligible to be Participants (the "Committee"), shall be responsible for establishing the overall Plan, administering the Plan, determining whether actual individual compensation awards will be paid, and approving the amount of the actual individual compensation awards.

The individual PC members, SMC members, or named exempt employees are responsible for the preparation of all forms and reports for reporting regarding their respective Plan accomplishments.

The members of the Board of Directors and all agents, officers, fiduciaries, and employees of the Company shall not be liable for any act, omission, interpretation, construction, or determination made in good faith in connection with their responsibilities with respect to the Plan; and the Company hereby agrees to indemnify the members of the Board of Directors and all agents, officers, fiduciaries, and employees of the Company in respect to any claim, loss, damage, or expense (including counsel fees) arising from any such act, omission, interpretation, construction, or determination to the full extent permitted by law.

The day-to-day administration of the Plan with regard to specific classes of employees shall be carried out as follows:

(a) CEO: The Board, or the Committee if one is appointed, is responsible for the day-to-day supervision of the Plan, including designation of the CEO's personal goals, determination of the achievement of such goals, determination of the award size relating to the CEO's goals, and the determination of the amount of the discretionary award.

(b) PC Members and Presidents: The CEO is responsible for the day-to-day supervision of the Plan, as it relates to a PC member and the two Presidents of WR's subsidiary and/or divisions, Kansas Gas and Electric Company and Gas Service Company ("Presidents"), including the designation of the PC member's and Presidents' personal goals, determination of the achievement of such goals, determination of the award size relating to the PC member's and Presidents' goals, and the determination of the amount of the discretionary award.

(c) SMC Members/Executive Vice Presidents: The Participant's Supervisor is responsible for the day-to-day supervision of the Plan, as it relates to a SMC member and WR Executive Vice President (EVP), including designation of the SMC member's and EVP's personal goals, determination of the achievement of such goals, determination of the award size relating to the SMC member's and EVP's goals, and the determination of the amount of the discretionary award.

(d) Select Exempt Employees: The Participant's Supervisor is responsible for the day-to-day supervision of the Plan, as it relates to a select exempt employee, including designation of the exempt employee's personal goals, determination of the achievement of such goals, determination of the award size relating to the exempt employee's goals, and the determination of the amount of the discretionary award.

3. Eligibility to Participate. Only employees who are members of WR's President's Council, members of WR's Senior Management Council, and WR exempt employees in pay grades 30 and above shall automatically be eligible to participate in the Plan. The Board of Directors, or the Committee if one shall be appointed, shall determine, from time to time, whether the

benefits of the Plan should be extended to other groups of employees of the Company.

4. Award Criteria. This Plan incorporates three types of criteria: financial, individual, and discretionary. The detailed measurement methods for PC members and Presidents, SMC members/EVP, and select exempt employees are as follows:

(a) PC Members and Presidents.

(1) Financial Criteria (50%). The individual PC member and Presidents are eligible to receive up to 50% of the total incentive award based on the overall company profitability as compared to budget. In other words, the individual may receive up to an additional 15% of base compensation if certain company standards are met when actual profitability is compared to budgeted profitability. However, an additional award may be available if certain financial criteria is met.

% of Actual Profitability to Budgeted Profitability	Financial Criteria Award
110% or more of Budget	70%
105% to 109% of Budget	60%
100% to 104% of Budget	50%
95% to 99% of Budget	40%
90% to 94% of Budget	30%
Less than 90% of Budget	0%

The percentage of actual to budgeted profitability is rounded to the nearest whole percent.

(2) Individual Criteria (30%). The individual PC member and Presidents and the CEO design the specifics of this criteria, except for the CEO's individual criteria, which is designed by the CEO and the Board. The individual and the CEO may settle on financial criteria or nonfinancial criteria or both. They must annually agree on the specific criteria. They may also determine how to use the criteria and measure the PC member and President's performance. Under this criteria, the individual is eligible to receive up to 30% of the total incentive award or an additional 9% of base compensation. The CEO is eligible to receive up to 30% of the total incentive award or an additional 9% of base compensation.

(3) Discretionary Criteria (20%). The individual PC member and Presidents are eligible to receive up to 20% of the total incentive award or an additional 6% of base compensation. This criteria is solely at the CEO's discretion, except for the CEO's award, which is at the Board's discretion.

(b) SMC Members/EVP.

(1) Financial Criteria (40%/50%). The individual SMC member is eligible to receive up to 40% of the total incentive award based on the overall Company profitability as compared to budget. In other words, the SMC member may receive up to an additional 4% of base compensation if certain Company standards are met when actual profitability is compared to budgeted profitability. However, an additional award may be available if certain financial criteria is met.

% of Actual Profitability to Budgeted Profitability	Financial Criteria Award
110% or more of Budget	60%
105% to 109% of Budget	50%
100% to 104% of Budget	40%
95% to 99% of Budget	30%
90% to 94% of Budget	20%
Less than 90% of Budget	0%

The individual EVP is eligible to receive up to 50% of the total incentive award based on the overall Company profitability as compared to budget. In other words, the EVP may receive up to an additional 10% of base compensation if certain Company standards are met when actual profitability is compared to budgeted profitability. However, an additional award may be available if certain financial criteria is met.

% of Actual Profitability to Budgeted Profitability	Financial Criteria Award
110% or more of Budget	70%
105% to 109% of Budget	60%
100% to 104% of Budget	50%
95% to 99% of Budget	40%
90% to 94% of Budget	30%
Less than 90% of Budget	0%

The percentage of actual to budgeted profitability is rounded to the nearest whole percent.

(2) Individual Criteria (40%/30%). The individual SMC member and EVP and the PC contact design the specifics of this criteria. The individual and the PC contact may settle on financial criteria or nonfinancial criteria or both. They must annually agree on the specific criteria. They must also determine how to use the criteria and measure the SMC member's and EVP's performance. Under this criteria, the individual SMC member is eligible to receive up to 40% of the total incentive award or an additional 4% of base compensation. The individual EVP is eligible to receive up to 30% of the total incentive award or an additional 6% of base compensation.

(3) Discretionary Criteria (20%). The individual SMC member is eligible to receive up to 20% of the total incentive award or an additional 2% of the base compensation. The EVP is eligible to receive up to 20% of the total incentive award or an additional 4% of base compensation. This criteria is solely at the PC contact's discretion.

(c) Select Exempt Employees.

(1) Financial Criteria (30%). The select exempt employee is eligible to receive up to 30% of the total incentive award based on the overall Company profitability as compared to budget. In other words, the exempt employee may receive up to an additional 1.5% of base compensation if certain Company standards are met when actual profitability is compared to budgeted profitability. However, an additional award may be available if certain financial criteria is met.

% of Actual Profitability to Budgeted Profitability	Financial Criteria Award
110% or more of Budget	50%
105% to 109% of Budget	40%
100% to 104% of Budget	30%
95% to 99% of Budget	20%
90% to 94% of Budget	10%
Less than 90% of Budget	0%

The percentage of actual to budgeted profitability is rounded to the nearest whole percent.

(2) Individual Criteria (50%). The select exempt employee and the PC or SMC contact design the specifics of this criteria. The individual and PC or SMC contact may settle on financial criteria or nonfinancial criteria or both. They must annually agree on the specific criteria. They must also determine how to use the criteria and measure the exempt employee's performance. Under this criteria, the individual is

eligible to receive up to 50% of the total incentive award or an additional 2.5% of base compensation.

(3) Discretionary Criteria (20%). The select exempt employee is eligible to receive up to 20% of the total incentive award or an additional 1% of base compensation. This criteria is solely at the PC or SMC contact's discretion.

5. Payment of Awards.

(a) Generally. The incentive compensation award, if adopted for the year, is payable annually. The payment shall be made in February following the Plan year for which the award was approved.

(b) Termination of Employment. A Participant who ceases to be continually employed by the Company (other than as a result of a Company-approved leave of absence or the Participant's death, disability, or retirement under the Company pension plan's early or normal retirement provisions) shall forfeit all rights to an annual incentive award for the year not yet ended.

(c) Payment in the Event of Death, Disability, or Retirement. If a participant dies, becomes disabled, or retires under the Company pension plan's early or normal retirement provisions, his or her actual incentive compensation award for the year, determined in accordance with the provisions of the Plan, shall be reduced to reflect only participation prior to termination. This reduction is based on the number of months the individual was an active Participant in the Plan in the year of termination. In the event of the Participant's death while the Plan is in effect, payments of any amounts due under such Plan shall be made to the Participant's designated beneficiary or to the Participant's estate.

6. Withholding for Taxes. The Company will provide for the withholding of any taxes required by any governmental authority with respect to any payment that is to be made under the Plan. The amount withheld shall be paid over by the Company to such governmental authority for the account of the Participant entitled to the payment.

7. Designation of Beneficiary. A Participant shall designate a Beneficiary or Beneficiaries on the Beneficiary Designation form in the appendix (which may be designated contingently and which may be an entity other than a natural person) to receive any amounts which under the terms of the Plan may become payable on or after the Participant's death. Any such designation may, unless the Participant has waived such right, from time to time and at any time, be changed or canceled by the Participant without the consent of a Beneficiary. Any such designation must be in writing and filed with the Board of Directors . If a Participant designates more than one Beneficiary, any payments under the Plan to such Beneficiaries shall be made in equal shares unless the Participant has designated otherwise, in which case the payments shall be made in the shares designated by the Participant. If a Participant does not designate a beneficiary or there is no proper designation of a Beneficiary or no person designated as a Beneficiary shall survive the Participant by 30 days, the Participant's Beneficiary shall be his or her estate.

8. No Rights to Corporate Assets. Nothing contained herein shall be construed as giving a Participant, his or her Beneficiary, or any other person any equity or other interest of any kind in any assets of the Company or creating a trust of any kind or a fiduciary relationship of any kind between the Company and any such person. As to any claim for any unpaid amounts under the Plan, a Participant, his or her Beneficiary, and any other person having a claim for payments shall be unsecured creditors.

9. Non-Assignability. Except as provided in Section 7, neither a Participant nor a Participant's Beneficiary shall have the power or right to transfer, assign, anticipate, mortgage, or otherwise encumber his or her interest in the Plan; nor shall such interest be subject to seizure for the payment of a Participant's or Beneficiary's debts, judgments, alimony, or separate maintenance or be transferable by operation of law in

the event of a Participant's or Beneficiary's bankruptcy or insolvency.

The Company's obligations under the Plan are not assignable or transferable except to a Company which acquires all or substantially all of the assets of the Company or to any corporation into which the Corporation may be merged or consolidated.

10. Amendment and Termination. The Board of Directors may from time to time and at any time alter, amend, suspend, discontinue, or terminate the Plan. Nothing contained in the Plan shall be construed to prevent the Company from taking any corporate action which is deemed by the Company to be appropriate or in its best interest, whether or not such action would have an adverse effect on the Plan or any Participant's interest in the Plan. Neither any Participant nor any other person shall have any claim against the Company as a result of any such action. Notwithstanding the foregoing, the Company may not modify (or terminate) the Plan to the extent doing so would adversely affect the rights of Participants to an Incentive Award at the time of the modification.

11. No Right of Employment. Nothing contained in the Plan shall be construed as conferring upon a Participant the right to continue in the employ of the Company.

12. Governing Law. All rights and obligations under the Plan shall be governed by, and the Plan shall be construed in accordance with the laws of the State of Kansas.

13. Titles and Headings. Titles and headings to sections herein are for purposes of reference only and shall in no way limit, define, or otherwise affect the meaning or interpretation of any provisions of the Plan.

14. Effective Date. The Plan shall become effective January 1, 1990.

____
Secretary

BENEFICIARY DESIGNATION

Pursuant to Section 7 of the Western Resources' Short-Term Incentive Plan, the Participant hereby designates as Primary Beneficiary under this Plan:

____

____

and, Participant hereby designates as Secondary Beneficiary under this Plan:

____

____

The term "Beneficiary" as used herein shall mean the Primary Beneficiary if such Primary Beneficiary shall survive Participant by at least 30 days, and shall mean the Secondary Beneficiary if Primary Beneficiary does not survive Participant by at least 30 days, and shall mean the Estate of the Participant, if neither Primary nor Secondary Beneficiary survives the Participant by at least 30 days. Participant shall have the right to change Participant's designation of Primary and/or Secondary Beneficiary from time to time in such manner as shall be required by the Board of Directors or the Committee, it being agreed that no change in beneficiary shall be effective until acknowledged in writing by the Company.

IN WITNESS WHEREOF, Participant has executed this designation this __________ day of _______________________, 19____.

PARTICIPANT:

____

(signature)

____

(type or print name)

Exhibit 10(k)

WESTERN RESOURCES, INC.

OUTSIDE DIRECTORS' DEFERRED COMPENSATION PLAN

Amended and Restated November 20, 1991

I. ESTABLISHMENT

The Board of Directors of Western Resources, Inc. (hereinafter called the "Company") on September 15, 1990, established a Non-Qualified Deferred Compensation Plan pursuant to which Outside Directors of the Company who are in a position to contribute to its continued growth, development and future financial success may be offered an opportunity to defer all or a portion of their compensation under terms and conditions that will represent a meaningful compensation benefit to them. The Plan is amended and restated according to the terms herein, effective November 20, 1992, and all deferred amounts shall be subject to the terms hereof.

II. PURPOSE

The purpose of the Plan is to improve the Company's ability to attract and retain Outside Directors who will contribute to the overall success of the Company.

III. DEFINITIONS

BENEFICIARY shall mean any person designated by the Participant on a form supplied by the Plan Administrator and if no beneficiary is designated, then the Participant's estate.

BOARD shall mean the Board of Directors of the Company.

COMPANY shall mean Western Resources, Inc., a Kansas corporation, or any successor thereto.

OUTSIDE DIRECTOR shall mean any director of the Company who is not also an employee of the Company.

PARTICIPANT shall mean any Outside Director of the Company who elects to defer fees hereunder.

PLAN shall mean Western Resources, Inc. Outside Directors' Deferred Compensation Plan as set forth in its entirety in this document as it may be amended from time to time.

PLAN ADMINISTRATOR shall mean the Human Resources Committee of the Company's Board of Directors or any other committee appointed by the Board of Directors to act in said capacity.

PLAN YEAR shall mean the calendar year.

PRONOUNS Masculine pronouns used herein shall refer to men or women or both and nouns and pronouns when stated in the singular shall include the plural and when stated in the plural shall include the singular, wherever appropriate.

IV. EFFECTIVE DATE

The Plan, as amended and restated herein, will become effective on November 20, 1991.

V. HISTORY

The Outside Directors of the Company are paid an annual retainer and a per meeting fee. The Plan allows the Outside Directors to elect to defer all, part, or none of their retainer and/or meeting fees. The Outside Directors have two investment alternatives from which to choose: Cash Deferral and Phantom Stock.

VI. ADMINISTRATION OF THE PLAN

The Plan shall be administered by the Compensation Committee of the Board of Directors of the Company or by such other Committee as may be appointed by the Board from time to time. Each designated Plan Participant shall enter into a written agreement (including the execution of the appropriate exhibits thereto) with the Company which contains the detailed provisions of the Plan.

VII. ELIGIBILITY

All Outside Directors of the Company shall be eligible to participate.

VIII. ELECTION TO DEFER

The Plan is a voluntary participation plan. The Outside Director must irrevocably elect to defer the designated portion of his annual retainer and/or meeting fees. Such election is made by entering into a written agreement with the Company prior to the Director providing service to the Company as Director. All deferrals must be for a minimum of six months.

Directors are elected in early May of each year. To be eligible to defer amounts during his initial year, the Director must make the election to defer the amounts as soon as elected but no later than May 21. This election is effective until December 31 of the first year of the Director's term.

If during a year, it becomes necessary to replace a Director, the new Director must make the election as soon as possible after his appointment but not later than fourteen (14) days after appointment.

For subsequent years, the agreement must be entered into on or before December 31 of the year preceding the year for which the deferral is to be effective. In years subsequent to the execution of the above agreement, a new election to defer shall be evidenced by the execution and delivery on or before December 31 immediately prior to the year it is to be effective, of a deferral election form prescribed for that purpose by the Human Resources Committee.

The Director must elect the amount, if any, to be deferred, the deferral option and timing of payments. All of the above are defined below.

IX. AMOUNT TO BE DEFERRED

The Director may defer all, a portion or none of the annual retainer, designated as a percentage of the retainer. The Director may also defer all, a portion or none of the per meeting fee, designated as a percentage of the fee.

X. DEFERRAL PLAN OPTIONS

The Director may choose one of the following deferral options: cash deferral or phantom stock. All amounts deferred are subject to terms of the option elected. The election is made as part of the election process of part VIII.

(a) Cash Deferral

Under the cash deferral option, the Director elects to defer the receipt of the cash payment of all or a portion of his annual retainer and/or meeting fee. Interest will accrue at the rate defined in Part XI.

(b) Phantom Stock

Under the phantom stock option, the Director elects to defer all or a portion of his annual retainer and/or meeting fee. The Director receives credit for "stock units" that represent shares of the Company's common stock equal to the amount deferred.

(1) The number of "stock units" received is dependent on the fair market value of the Company's common stock on the measurement date.

(2) "Fractional stock units" will be accounted for as non-interest bearing cash.

(3) The measurement date is the regular payment date of the retainer and/or meeting fee. The "stock units" will be measured at the closing price on the date the deferred amount would have been paid.

(4) Dividend reinvestment is discussed in Part XI.

XI. DEFERRED COMPENSATION ACCOUNT

The Company will establish a separate "account" for each Participant and will credit to said account the compensation deferred by the Participant. The amount deferred under the cash deferral option will earn interest at the New York prime rate and will be credited quarterly (March 15, June 15, September 15, and December 15).

The Director's account is deemed to receive "dividends" on the "units" of phantom stock equal to the dividends paid on the Company's common stock. The dividend received will be treated similar to the Company's Dividend Reinvestment Program and will be used to purchase additional "units" of the Company's stock at the closing price of the stock on the date the common stock dividend is paid. Any fractional stock units will be accounted for as non-interest bearing cash. The account is also adjusted for any stock dividends, stock splits, etc. In the event the Company's Dividend Reinvestment Program is modified in any way, dividends paid through this Plan will be made in accordance with said modification. If the Company's Dividend Reinvestment Program is terminated, dividends made through this Plan will continue to be reinvested in accordance with the provisions of the terminated Dividend Reinvestment Program.

The amount equal to the balance in the account of the Participant, taking into account all credits, shall be the Participant's deferred compensation benefit available from time to time under the terms hereof.

XII. DISTRIBUTION FROM THE DEFERRED COMPENSATION ACCOUNT

By written irrevocable election made at the time of each deferral election, the Director must select one of the following methods for receipt of the balance in his deferred compensation account:

(a) lump sum at termination; or

(b) paid monthly over a specified number of years determined by the irrevocable election.

The balance in the deferred compensation account becomes measurable at the end of the Director's term.

The balance to be distributed in the deferred compensation account under the cash deferral option is the cash balance of the account. The balance to be distributed in the deferred compensation account under the phantom stock option is an amount equal to the credited "stock units'" fair market value at the time the account becomes measurable.

At the time the account balance becomes measurable, the account balance is valued. From that date forward, any remaining balance (i.e., balance during time of installment payments) shall bear interest at the New York prime rate.

Distribution in the form elected by the Director shall commence immediately upon the occurrence of any of the following events: death, retirement, disability, or termination, if such event occurs prior to the distribution date elected by the Director.

The Director shall also designate a beneficiary to receive the unpaid balance of the value of his account in the event of his death prior to complete distribution of such unpaid balance. If no beneficiary is designated, then his estate will be deemed his beneficiary. Distribution after the death of a Participant shall be in the form selected by the Participant.

XIII. STATE LAWS GOVERNING PLAN

This Plan shall be governed by the laws of the State of Kansas.

AMENDMENT OR TERMINATION

This Plan shall continue in effect until amended or terminated by the Company's Board of Directors. Any such amendment or termination shall not adversely affect any agreement theretofore entered into with a designated Director.

This Amended and Restated Plan was adopted by the Board on November 20, 1991.

Western Resources, Inc.

____
John K. Rosenberg
Executive Vice President and
General Counsel

DEFERRED COMPENSATION AGREEMENT

THIS AGREEMENT, made as of the ______ day of ______________, 19____, by and between Western Resources, Inc. with executive and general offices at 818 Kansas Avenue, Post Office Box 889, Topeka, Kansas 66601 (hereinafter called the "Company"), and _________________________ residing at ___________________________ hereinafter called "Director").

WITNESSETH in consideration of the premises, and the mutual promises and agreements herein contained, the parties hereto agree as follows, intending to be legally bound hereby:

1. Agreement Incorporates Plan

The terms of Western Resources, Inc. Outside Directors' Deferred Compensation Plan (hereinafter referred to as "Plan") effective _______________, 199___, are hereby incorporated herein and made a part hereof as if set out verbatim. Said Plan and this Agreement set forth the terms which govern and control Director's participation in the Plan.

2. Exhibits A and B are Incorporated Herein

Exhibit A, which is the Election Deferring Compensation described in the Plan, is attached hereto and made a part hereof. Exhibit B, which is Director's Designation of Beneficiary, is attached hereto and made a part hereof.

3. Agreement to Participate

By execution of this Agreement, Director hereby agrees to participate in the Plan pursuant to the terms hereof, elect to defer compensation pursuant to Exhibit A, and designates his Beneficiary pursuant to Exhibit B.

4. Restrictions Against Alienation

Neither the Director nor his Beneficiary shall have any right to commute, sell, assign, transfer, or otherwise convey or encumber the rights to receive any payments hereunder, which payments and all the rights thereto are expressly declared to be nonassignable and nontransferable.

5. Termination of the Agreement by the Company

The Company may terminate this Agreement at any time. If the Company terminates this Agreement, the Company shall pay Director or his Beneficiary an amount equal to the value of his account as described in the Plan in the amount(s) and at the time(s) elected by the Director hereunder.

6. What Constitutes Notice to the Director

Any notice to Director hereunder may be given either by hand delivering it to Director or by depositing it in the United States Mail, postage prepaid, return receipt requested, addressed to his last known address.

7. Advance Disclaimer of Any Waiver on the Part of the Company

Failure to insist upon strict compliance with any of the terms, covenants, or conditions hereof shall not be deemed a waiver of such term, covenant, or condition, nor shall any waiver or relinquishment of any right or power hereunder at any one or more times be deemed a waiver or relinquishment of such right or power at any other time or times.

8. Effect of Invalidity of Any Part of the Agreement Upon the Whole Agreement

The invalidity or unenforceability of any provision hereof shall in no way affect the validity or enforceability of any other provision.

9. Agreement Binding on Any Successor Owner

Except as otherwise provided herein, this Agreement shall inure to the benefit of and be binding upon Director, his heirs, executors, and administrators and upon the Company, its successors and assigns, including but not limited to any corporation which may acquire all or substantially all of the Company's assets and business or with or into which the Company may be consolidated or merged.

10. State Laws Governing this Agreement

This Agreement shall be governed by the laws of the State of Kansas.

11. Counterparts of this Agreement and Director's Acknowledgement that he has Read and Understands all parts of this Agreement

This Agreement has been executed in several counterparts, each of which shall be an original, but such counterparts shall together constitute but one (1) instrument. Director acknowledges that he has read all parts of the Plan and this Agreement, including Exhibits A and B annexed hereto and made a part of this Agreement and has sought and obtained satisfactory answer(s) to any question(s) he had as to his rights, obligations, and potential liabilities under this Agreement prior to affixing his signature and initials to any part of this Agreement.

IN WITNESS WHEREOF, the parties hereto have executed this Agreement as of the day and year first above written.

ATTEST: WESTERN RESOURCES, INC.

______________________________ By: ___________________________
Name: _________________________
WITNESS: Title: ________________________

___________________________ ___________________________
Director
Name: _________________________
(Please Print)

Exhibit 12

WESTERN RESOURCES, INC.
Computations of Ratio of Earnings to Fixed Charges and
Computations of Ratio of Earnings to Combined Fixed Charges
and Preferred and Preference Dividend Requirements
(Thousands of Dollars)

	Year Ended December 31,				
	1993	1992	1991	1990	1989
Net Income.	$177,370	$127,884	$ 89,645	$ 79,619	$ 72,778
Taxes on Income	78,755	46,099	42,527	36,736	35,171
Net Income Plus Taxes.	256,125	173,983	132,172	116,355	107,949
Fixed Charges:					
Interest on Long-Term Debt.	123,551	117,464	51,267	51,542	46,378
Interest on Other Indebtedness. . .	19,255	20,009	10,490	11,022	8,742
Interest on Corporate-owned Life Insurance Borrowings	16,252	5,294	-	-	-
Interest Applicable to Rentals	28,827	27,429	5,089	4,426	4,673
Total Fixed Charges	187,885	170,196	66,846	66,990	59,793
Preferred and Preference Dividend Requirements:					
Preferred and Preference Dividends.	13,506	12,751	6,377	1,744	1,857
Income Tax Required	5,997	4,596	3,025	805	897
Total Preferred and Preference Dividend Requirements	19,503	17,347	9,402	2,549	2,754
Total Fixed Charges and Preferred and Preference Dividend Requirements. .	207,388	187,543	76,248	69,539	62,547
Earnings (1).	$444,010	$344,179	$199,018	$183,345	$167,742
Ratio of Earnings to Fixed Charges. .	2.36	2.02	2.98	2.74	2.81
Ratio of Earnings to Combined Fixed Charges and Preferred and Preference Dividend Requirements	2.14	1.84	2.61	2.64	2.68

(1) Earnings are deemed to consist of net income to which has been added income taxes (including net deferred investment tax credit) and fixed charges. Fixed charges consist of all interest on indebtedness, amortization of debt discount and expense, and the portion of rental expense which represents an interest factor. Preferred and preference dividend requirements consist of an amount equal to the pre-tax earnings which would be required to meet dividend requirements on preferred and preference stock.

Exhibit 23(a)

CONSENT OF INDEPENDENT PUBLIC ACCOUNTANTS

As independent public accountants, we hereby consent to the incorporation of our report included in this Form 10-K, into the Company's previously filed Registration Statements File Nos. 33-23021, 33-23022, 33-23023, and 33-47344 on Form S-8 and Nos. 33-49467, 33-49505, 33-49553, and 33-50069 on Form S-3.

ARTHUR ANDERSEN & CO.

Kansas City, Missouri,
March 18, 1994

Exhibit 23(b)

INDEPENDENT AUDITORS' CONSENT

We consent to the use in this Annual Report on Form 10-K of Western Resources, Inc. for the year ended December 31, 1993 of our report dated January 29, 1993 appearing in the Annual Report on Form 10-K of Kansas Gas and Electric Company for the year ended December 31, 1993.

DELOITTE & TOUCHE

Kansas City, Missouri
March 18, 1994

UNITED STATES
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

For the fiscal year ended December 31, 1993

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

Commission file number 1-7324

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

KANSAS	48-1093840
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
P.O. BOX 208, WICHITA, KANSAS	67201
(Address of Principal Executive Offices)	(Zip Code)

Registrant's telephone number, including area code 316/261-6611

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

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

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

Indicate the number of shares outstanding of each of the registrant's classes of common stock.

Common Stock, No par value	1,000 Shares
(Title of each class)	(Outstanding at March 18, 1994)

Indicated 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

Registrant meets the conditions of General Instruction J(2)(c) to Form 10-K for certain wholly-owned subsidiaries and is therefore filing an abbreviated form.

KANSAS GAS AND ELECTRIC COMPANY
FORM 10-K
December 31, 1993

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PART I

ITEM 1. BUSINESS

ACQUISITION AND MERGER

On March 31, 1992, Western Resources, Inc. (formerly The Kansas Power and Light Company) (Western Resources) through its wholly-owned subsidiary KCA Corporation (KCA), acquired all of the outstanding common and preferred stock of Kansas Gas and Electric Company (KG&E) for $454 million in cash and 23,479,380 shares of Western Resources common stock (the Merger). Western Resources also paid approximately $20 million in costs to complete the Merger. Simultaneously, KCA and Kansas Gas and Electric Company merged and adopted the name Kansas Gas and Electric Company (the Company, KG&E).

Additional information relating to the Merger can be found in Management's Discussion and Analysis of Financial Condition and Results of Operations and Note 1 of the Notes to Financial Statements.

GENERAL

The Company is an electric public utility engaged in the generation, transmission, distribution and sale of electric energy in the southeastern quarter of Kansas including the Wichita metropolitan area. The Company owns 47 percent of Wolf Creek Nuclear Operating Corporation, the operating company for Wolf Creek Generating Station (Wolf Creek). Corporate headquarters of the Company is located in Wichita, Kansas. The Company has no gas properties. At December 31, 1993, the Company had no employees. All employees are provided by Western Resources.

As a regulated utility, the Company does not have direct competition for retail electric service in its certified service area. However, there is competition, based largely on price, from the generation, or potential generation, of electricity by large commercial and industrial customers, and independent power producers.

The Company's business is subject to seasonal fluctuations with the peak period occurring during the summer. Approximately one-third of residential kilowatthour sales occur in the third quarter. Accordingly, earnings and revenue information for any quarterly period should not be considered as a basis for estimating results of operations for a full year.

Electric utilities have been experiencing problems such as controversy over the safety and use of coal and nuclear power plants, compliance with changing environmental requirements, long construction periods required to complete new generating units resulting in high fixed costs for those facilities, difficulties in obtaining timely and adequate rate relief to recover these high fixed costs, uncertainties in predicting future load requirements, competition from independent power producers and cogenerators, and the effects of changing accounting standards.

The problems which most significantly affect the Company are the use, or potential use, of cogeneration and self-generation facilities by large commercial and industrial customers, and compliance with environmental requirements. For additional information see Management's Discussion and Analysis and Notes 3 and 4 of the Notes to Financial Statements.

Discussion of other factors affecting the Company are set forth in the Notes to Financial Statements and Management's Discussion and Analysis included herein.

ELECTRIC OPERATIONS

General. The Company supplies electric energy at retail to approximately 268,000 customers in 139 communities in Kansas. The Company also supplies electric energy to 27 communities and 1 rural electric cooperative, and has contracts for the sale, purchase or exchange of electricity with other utilities at wholesale.

The Company's electric sales for the last five years were as follows:

	1993	1992	1991	1990	1989
			(Thousands of MWH)		
Residential	2,386	2,102	2,341	2,270	2,105
Commercial	1,991	1,892	1,908	1,838	1,748
Industrial	3,323	3,248	3,194	3,093	2,978
Other	2,049	1,313	1,214	1,736	2,113
Total	9,749	8,555	8,657	8,937	8,944

The Company's electric revenues for the last five years were as follows:

	1993	1992	1991	1990 (1)	1989
			(Thousands of Dollars)		
Residential	$219,069	$194,142	$219,907	$214,544	$187,657
Commercial	162,858	154,005	155,847	151,098	135,740
Industrial	179,256	174,226	172,953	168,294	153,360
Other	55,814	31,878	46,261	52,705	56,776
Total	$616,997	$554,251	$594,968	$586,641	$533,533

(1) See Note 4 of the Notes to Financial Statements for impact of rate refund orders.

Capacity. The aggregate net generating capacity of the Company's system is presently 2,472 megawatts (MW). The system comprises interests in twelve fossil fueled steam generating units, one nuclear generating unit (47% interest) and one diesel generator, located at seven generating stations. One of the twelve fossil fueled units has been "mothballed" for future use (see Item 2. Properties).

The Company's 1993 peak system net load occurred on August 16, 1993 and amounted to 1,811 MW. The Company's net generating capacity together with power available from firm interchange and purchase contracts, provided a capacity margin of approximately 22% above system peak responsibility at the time of the peak.

The Company and ten companies in Kansas and western Missouri have agreed to provide capacity (including margin), emergency and economy services for each other. This arrangement is called the MOKAN Power Pool. The pool participants also coordinate the planning of electric generating and transmission facilities.

Future Capacity. The Company does not contemplate any significant expenditures in connection with construction of any major generating facilities through the turn of the century (see Management's Discussion and Analysis, Liquidity and Capital Resources). The Company has capacity available which may not be fully utilized by growth in customer demand for at least 5 years. The Company continues to market this capacity and energy to other utilities.

Fuel Mix. The Company's coal-fired units comprise 1,092 MW of the total 2,472 MW of generating capacity and the Company's nuclear unit provides 533 MW of capacity. Of the remaining 847 MW of generating capacity, units that can burn either natural gas or oil account for 844 MW, and the remaining unit which burns only diesel accounts for 3 MW (see Item 2, Properties).

During 1993, low sulfur coal was used to produce 60% of the Company's electricity. Nuclear produced 33% and the remainder was produced from natural gas, oil, or diesel. Based on the Company's estimate of the availability of fuel, coal will continue to be used to produce approximately 61% of the Company's electricity and 33% from nuclear.

The Company anticipates the fuel mix to fluctuate with the operation of the nuclear powered Wolf Creek which operates on an 18-month refueling and maintenance schedule. The 18-month schedule permits uninterrupted operation every third calendar year. Beginning March 5, 1993, Wolf Creek was taken off-line for its sixth refueling and maintenance outage. The refueling outage took approximately 73 days to complete, during which time electric demand was met primarily by the Company's coal-fired generating units.

Nuclear. The owners of Wolf Creek have on hand or under contract 73 percent of the uranium required for operation of Wolf Creek through the year 2001. The balance is expected to be obtained through spot market and contract purchases.

Contractual arrangements are in place for 100 percent of Wolf Creek's uranium enrichment requirements for 1993-1996, 70 percent for 1997-1998 and 100 percent for 2003-2014. The balance of the 1997-2002 requirements is expected to be obtained through a combination of spot market and contract purchases. The decision not to contract for the full enrichment requirements is one of cost rather than availability of service.

Contractual arrangements are in place for the conversion of uranium to uranium hexafluoride sufficient to meet Wolf Creek's requirements through 1995 as well as the fabrication of fuel assemblies to meet Wolf Creek's requirements through 2012. During 1994, the Company plans to begin securing additional arrangements, for the post 1995 period.

The Nuclear Waste Policy Act of 1982 established schedules, guidelines and responsibilities for the Department of Energy (DOE) to develop and construct repositories for the ultimate disposal of spent fuel and high-level waste. The DOE has not yet constructed a high-level waste disposal site and has announced that a permanent storage facility may not be in operation prior to 2010 although an interim storage facility may be available earlier. Wolf Creek contains an on-site spent fuel storage facility which, under current regulatory guidelines, provides space for the storage of spent fuel through 2006 while still maintaining full core off-load capability. The Company believes adequate additional storage space can be obtained, as necessary.

Coal. Western Resources, the operator of Jeffrey Energy Center (JEC) and KG&E (20% interest in JEC), have a long-term coal supply contract with Amax Coal West, Inc. (AMAX), a subsidiary of Cyprus Amax Coal Company, to supply low sulfur coal to JEC from AMAX's Eagle Butte Mine or an alternate mine source of AMAX's Belle Ayr Mine, both located in the Powder River Basin in Campbell County, Wyoming. The contract expires December 31, 2020. The contract contains a schedule of minimum annual delivery quantities with deficient mmBTU provisions applicable to deficiencies in the scheduled delivery. The coal to be supplied is surface mined and has an average BTU content of approximately 8,300 BTU per pound and an average sulfur content of .43 lbs/mmBTU (see Environmental Matters). The average delivered cost of coal for JEC was approximately $1.045 per mmBTU or $17.35 per ton during 1993.

Coal is transported by Western Resources from Wyoming under a long-term rail transportation contract with Burlington Northern (BN) and Union Pacific (UP) to JEC through December 31, 2013. Rates are based on net load carrying capabilities of each rail car. Western Resources provides 770 aluminum rail cars, under a 20 year lease, to transport coal to JEC. During 1994 Western Resources will provide an additional 120 rail cars under a similar lease.

The two coal fired units at La Cygne generating station have an aggregate generating capacity of 677 MW (KG&E's 50 percent share) (see Item 2. Properties). The operator, Kansas City Power & Light Company (KCP&L), maintains coal contracts as discussed in the following paragraphs.

During 1993, La Cygne 1 was converted to use low sulfur Powder River Basin coal which is supplied under the AMAX contract for La Cygne 2, discussed below. Illinois or Kansas/Missouri coal is blended with the Powder River Basin coal and is secured from time to time under spot market arrangements. La Cygne 1 uses a blend of 85 percent Powder River Basin coal. During the third and fourth quarters of 1993, the Company along with the operator secured supplemental Illinois or Kansas/Missouri coal, for blending purposes, on a short-term basis through spot market purchase orders.

La Cygne 2 and additional La Cygne 1 Powder River Basin coal was supplied, through a contract that expired December 31, 1993, by AMAX from its mines in Gillette, Wyoming. This low sulfur coal had an average BTU content of approximately 8,500 BTU per pound and a maximum sulfur content of .50 lbs/mmBTU (see Environmental Matters). For 1994, the operator has secured Powder River Basin coal, similar to the AMAX coal, from two sources; Carter Mining Company's Caballo Mine, a subsidiary of Exxon Coal USA; and Caballo Rojo Inc's Caballo Rojo Mine, a subsidiary of Drummond Inc. Transportation is covered by KCP&L through its Omnibus Rail Transportation Agreement with BN and Kansas City Southern Railroad through December 31, 1995. An alternative rail transportation agreement with Western Railroad Property, Inc. (WRPI), a partnership between UP and Chicago Northwestern (CNW), lasts through December 31, 1995. The WRPI/UP/CNW agreement is a supplemental access contract to handle tonnages not covered by the Omnibus contract.

During 1993, the average delivered cost of all coal procured for La Cygne 1 was approximately $0.81 per mmBTU or $14.24 per ton and the average delivered cost of Powder River Basin coal for La Cygne 2 was approximately $0.84 per mmBTU or $14.18 per ton.

Natural Gas. The Company uses natural gas as a primary fuel in its Gordon Evans and Murray Gill Energy Centers. Natural gas for these generating stations is supplied under a firm contract that runs through 1995 by Kansas Gas Supply (KGS). Short-term economical spot market purchases from the Williams Natural Gas (WNG) system provide the Company flexible natural gas to meet operational needs.

Oil. The Company uses oil as an alternate fuel when economical or when interruptions to natural gas make it necessary. Oil is also used as a supplemental fuel at each of the coal plants. All oil burned by the Company during the past several years has been obtained by spot market purchases. At December 31, 1993, the Company had approximately 770 thousand gallons of No. 2 oil and 11.5 million gallons of No. 6 oil which is sufficient to meet emergency requirements and protect against lack of availability of natural gas and/or the loss of a large generating unit.

Other Fuel Matters. The Company's contracts to supply fuel for its coal- and natural gas-fired generating units, with the exception of JEC, do not provide full fuel requirements at the various stations. Supplemental fuel is procured on the spot market to provide operational flexibility and, when the price is favorable, to take advantage of economic opportunities.

On March 26, 1992, in connection with the Merger, the Kansas Corporation Commission (KCC) approved the elimination of the Energy Cost Adjustment Clause (ECA) for most Kansas retail customers of the Company effective April 1, 1992. The provisions for fuel costs included in base rates were established at a level intended by the KCC to equal the projected average cost of fuel through August 1995 and to include recovery of costs provided by previously issued orders relating to coal contract settlements and storm damage recovery. Any increase or decrease in fuel costs from the projected average will be absorbed by the Company.

Set forth in the table below is information relating to the weighted average cost of fuel used by the Company.

	1993	1992	1991	1990	1989
Per Million BTU:					
Nuclear	$0.35	$0.34	$0.32	$0.34	$0.34
Coal	0.96	1.25	1.32	1.32	1.38
Gas	2.37	1.95	1.74	1.96	1.91
Oil	3.15	4.28	4.13	3.01	3.30
Cents per KWH Generation	0.93	0.98	1.09	1.01	0.96

Environmental Matters. The Company currently holds all Federal and State environmental approvals required for the operation of all its generating units. The Company believes it is presently in substantial compliance with all air quality regulations (including those pertaining to particulate matter, sulfur dioxide and nitrogen oxides) promulgated by the State of Kansas and the Environmental Protection Agency (EPA).

The Federal sulfur dioxide standards applicable to the Company's JEC and La Cygne 2 units, prohibit the emission of more than 1.2 pounds of sulfur dioxide per million BTU of heat input. Federal particulate matter emission standards applicable to these units prohibit: (1) the emission of more than 0.1 pounds of particulate matter per million BTU of heat input and (2) an opacity greater than 20 percent. Federal nitrogen oxides emission standards applicable to these units prohibit the emission of more than 0.7 pounds of nitrogen oxides per million BTU of heat input.

The JEC and La Cygne 2 units have met: (1) the sulfur dioxide standards through the use of low sulfur coal (see Coal); (2) the particulate matter standards through the use of electrostatic precipitators; and (3) the nitrogen oxides standards through boiler design and operating procedures. The JEC units are also equipped with flue gas scrubbers providing additional sulfur dioxide and particulate matter emission reduction capability.

The Kansas Department of Health and Environment regulations, applicable to the Company's other generating facilities, prohibit the emission of more than 3.0 pounds of sulfur dioxide per million BTU of heat input at the Company's generating units. The Company has contracted to purchase low sulfur coal (see Coal) which will allow compliance with such limits at La Cygne. All facilities burning coal are equipped with flue gas scrubbers and/or electrostatic precipitators.

The Clean Air Act Amendments of 1990 (the Act) require a two-phase reduction in sulfur dioxide and nitrogen oxide emissions effective in 1995 and 2000 and a probable reduction in toxic emissions. To meet the monitoring and reporting requirements under the acid rain program, the Company is installing continuous monitoring and reporting equipment at a total cost of approximately $2.3 million. At December 31, 1993, the Company had completed approximately $850 thousand of these capital expenditures with the remaining $1.4 million of capital expenditures to be completed in 1994 and 1995. The Company does not expect additional equipment to reduce sulfur emissions to be necessary under Phase II. The Company currently has no Phase I affected units.

The nitrogen oxide and toxic limits, which were not set in the law, will be specified in future EPA regulations. The EPA has issued, for public comment, preliminary nitrogen oxide regulations for Phase I group 1 units. Nitrogen oxide regulations for Phase II units and Phase I group 2 units are mandated in the Act to be promulgated by January 1, 1997. Although the Company has no Phase I units, the final nitrogen oxide regulations for Phase 1 group 1 may allow for early compliance for Phase II group 1 units. Until such time as the Phase I group 1 nitrogen oxide regulations are final, the Company will be unable to determine its compliance options or related compliance costs.

All of the Company's generating facilities are in substantial compliance with the Best Practicable Technology and Best Available Technology regulations issued by EPA pursuant to the Clean Water Act of 1977. Most EPA regulations are administered in Kansas by the Kansas Department of Health and Environment.

Additional information with respect to Environmental Matters is discussed in Note 3 of the Notes to Financial Statements.

FINANCING

The Company's ability to issue additional debt is restricted under limitations imposed by the Mortgage and Deed of Trust of the Company.

The Company's mortgage prohibits additional first mortgage bonds from being issued (except in connection with certain refundings) unless the Company's net earnings before income taxes and before provision for retirement and depreciation of property for a period of 12 consecutive months within 15 months preceding the issuance are not less than two and one-half times the annual interest charges on, or 10% of the principal amount of, all first mortgage bonds outstanding after giving effect to the proposed issuance. Based on the Company's results for the 12 months ended December 31, 1993, approximately $1 billion principal amount of additional first mortgage bonds could be issued (7.5 percent interest rate assumed).

Additional KG&E bonds may be issued, subject to the restrictions in the preceding paragraph, on the basis of property additions not subject to an unfunded prior lien and on the basis of bonds which have been retired. As of December 31, 1993, the Company had approximately $1.3 billion of net bondable property additions not subject to an unfunded prior lien entitling the Company to issue up to $882 million principal amount of additional bonds. As of December 31, 1993, the Company could also issue up to $115 million bonds on the basis of retired bonds.

REGULATION AND RATES

The Company is subject as an operating electric utility to the jurisdiction of the KCC which has general regulatory authority over the Company's rates, extensions and abandonments of service and facilities, valuation of property, the classification of accounts and various other matters. The Company is also subject to the jurisdiction of the FERC and the KCC with respect to the issuance of the Company's securities.

Additionally, the Company is subject to the jurisdiction of the FERC, including jurisdiction as to rates with respect to sales of electricity for resale, and the Nuclear Regulatory Commission as to nuclear plant operations and safety.

Additional information with respect to Regulation and Rates is discussed in Notes 1 and 4 of the Notes to Financial Statements.

EXECUTIVE OFFICERS OF THE COMPANY

Name	Age	Present Office	Other Offices or Positions Held During Past Five Years
Kent R. Brown	48	Chairman of the Board, (since June 1992) President and Chief Executive Officer (since March 1992)	Group Vice President (1982 to 1992)
Richard D. LaGree	63	Vice President, Field Operations (since April 1992)	Vice President, Electric Distribution Operations, (1990 to 1992) Western Resources, Inc. Vice President, Western Region Operations (1985 to 1990) Western Resources, Inc.
Richard D. Terrill	39	Secretary, Treasurer and General Counsel (since April 1992)	Secretary and Attorney (1983 to 1992)

The present term of office of each of the executive officers extends to May 3, 1994, or until their respective successors are chosen and appointed by the Board of Directors. There are no family relationships among any of the officers, nor any arrangements or understandings between any officer and other persons pursuant to which he/she was elected as an officer.

ITEM 2. PROPERTIES

The Company owns or leases and operates an electric generation, transmission, and distribution system in Kansas.

During the five years ended December 31, 1993, the Company's gross property additions totalled $330,737,000, and retirements were $93,737,000.

ELECTRIC FACILITIES

Name	Unit No.	Year Installed	Principal Fuel	Unit Capacity (MW) (2)
Gordon Evans Energy Center:				
Steam Turbines	1	1961	Gas--Oil	150
	2	1967	Gas--Oil	367
Jeffrey Energy Center (20%):				
Steam Turbines	1	1978	Coal	140
	2	1980	Coal	135
	3	1983	Coal	140
La Cygne Station (50%):				
Steam Turbines	1	1973	Coal	342
	2	1977	Coal	335
Murray Gill Energy Center:				
Steam Turbines	1	1952	Gas--Oil	46
	2	1954	Gas--Oil	69
	3	1956	Gas--Oil	107
	4	1959	Gas--Oil	105
Neosho Energy Center:				
Steam Turbine	3	1954	Gas--Oil	0 (1)
Wichita Plant:				
Diesel Generator	5	1969	Diesel	3
Wolf Creek Generating Station (47%):				
Nuclear	1	1985	Uranium	533
Total				2,472

(1) This unit has been "mothballed" for future use.

(2) Based on MOKAN rating.

The Company jointly-owns Jeffrey Energy Center (20%), La Cygne Station (50%) and Wolf Creek Generating Station (47%).

ITEM 3. LEGAL PROCEEDINGS

Information on legal proceedings involving the Company is set forth in Note 10 of Notes to Financial Statements included herein.

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

Information required by Item 4 is omitted pursuant to General Instruction J(2)(c) to Form 10-K.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY AND RELATED STOCKHOLDER MATTERS

On March 31, 1992, Western Resources through its wholly-owned subsidiary KCA, acquired all of the outstanding common and preferred stock of KG&E. As a result, the Company's common stock was delisted by the New York Stock Exchange and the Pacific Stock Exchange.

ITEM 6. SELECTED FINANCIAL DATA

	1993	1992	1991	1990(1)	1989
	(Dollars in Thousands)				
Income Statement Data:					
Operating revenues	$ 616,997	$ 554,251	$ 594,968	$ 586,641	$ 533,533
Operating expenses	469,616	424,089	468,885	447,355	405,938
Operating income	147,381	130,162	126,083	139,286	127,595
Net income	108,103	77,981	53,602	64,184	47,493
Balance Sheet Data:					
Gross electric plant in service.	$3,339,832	$3,293,365	$2,468,959	$2,435,090	$2,388,640
Construction work in progress. .	28,436	29,634	13,612	14,760	13,181
Total assets	3,187,479	3,279,232	2,350,546	2,348,862	2,363,069
Long-term debt	653,543	871,652	850,851	824,424	726,537
Interest coverage ratio (before income taxes, including AFUDC)	3.58	2.35	1.90	2.07	1.71

(1) See Note 4 of the Notes to Financial Statements for impact of rate refund orders.

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

FINANCIAL CONDITION

The results of operations for the year ended December 31, 1993, and the nine months ended December 31, 1992, included herein, refer to the Company following the merger with Western Resources, Inc. (formerly The Kansas Power and Light Company) through its wholly-owned subsidiary, KCA Corporation, on March 31, 1992 (the Merger) (see Note 1).

Pro forma results of operations for the twelve months ended December 31, 1992 presented herein, give effect to the Merger as if it occurred on January 1, 1992 and were derived by combining the historical information for the three month period ended March 31, 1992 and the nine month period ended December 31, 1992. The results of operations for the year ended December 31, 1991, refer to the Company prior to the Merger but are not materially different than if presented on a pro forma basis. Additional information relating to changes between years is provided in the Notes to Financial Statements.

General: The Company had net income of $108.1 million for 1993 compared to pro forma net income of $78 million in 1992. The increase in net income is a result of the increase in energy sales due to the return of more normal temperatures compared to unusually mild winter and summer temperatures in 1992, Merger-related cost savings, and reduced interest charges.

Liquidity and Capital Resources: The Company's liquidity is a function of its ongoing construction program, designed to improve facilities which provide electric service and meet future customer service requirements.

During 1993, construction expenditures for the Company's electric system were approximately $61 million and nuclear fuel expenditures were approximately $6 million. It is projected that adequate capacity margins will be maintained through the turn of the century. The construction program is focused on providing service to new customers and improving present electric facilities.

First mortgage bond maturities and sinking fund requirements through 1998 are $18.6 million. This capital as well as capital required for construction will be provided from internal and external sources available under then existing financial conditions. During 1993, the Company issued and retired long-term debt to take advantage of favorable long-term interest rates and increased borrowings against the accumulated cash surrender values of the corporate-owned life insurance policies.

The embedded cost of long-term debt was 7.3% at December 31, 1993, a decrease from 7.5% at December 31, 1992. The decrease was primarily accomplished through refinancing of higher cost debt.

On November 22, 1993, the Company redeemed three series of first mortgage bonds, $25 million principal amount of First Mortgage Bonds, 7 3/8% Series due 2002, $25 million principal of First Mortgage Bonds, 8 3/8% Series due 2006, and $25 million principal of First Mortgage Bonds, 8 1/2% Series due 2007.

On September 20, 1993, the Company terminated a long-term revolving credit agreement which provided for borrowings of up to $150 million. The loan agreement, which was effective through October 1994, was repaid without penalty.

At December 31, 1993, the Company had $150 million of First Mortgage Bonds available to be issued under a shelf registration filed on August 24, 1993. On January 20, 1994, the Company issued $100 million of First Mortgage Bonds, 6.20% Series due January 15, 2006 under this shelf registration. The net proceeds were
used to reduce short-term debt.

On August 12, 1993, the Company issued $65 million of First Mortgage Bonds, 6 1/2% Series due August 1, 2005. The net proceeds from the new issue, together with available cash, were used to refund $35 million of First Mortgage Bonds, 8 1/8% Series due 2001, and $30 million of First Mortgage Bonds, 8 7/8% Series due 2008.

The Company has a long-term agreement that expires in 1995 which contains provisions for the sale of accounts receivable and unbilled revenues (receivables) and phase-in revenues up to a total of $180 million. Amounts related to receivables are accounted for as sales while those related to phase-in revenues are accounted for as collateralized borrowings. At December 31, 1993, the Company had receivables amounting to $56.8 million which were considered sold.

In 1986 the Company purchased corporate-owned life insurance policies (COLI) on certain of its employees. The annual cash outflow for the premiums on these policies from 1991 through 1993 was approximately $27 million. On August 23, 1993, the Company increased its borrowings against the accumulated cash surrender values of the policies by $164.7 million and received $6.9 million from increased borrowings on Wolf Creek Nuclear Operating Company (WCNOC) policies. Total 1993 COLI borrowings amounted to $184.6 million. See Note 2 of the Notes to Financial Statements for additional information on the accumulated cash surrender value. After 1993, the borrowings are expected to produce annual cash inflows, net of expenses, through the remaining life of the policies. Borrowings against the policies will be repaid from death proceeds.

The Company's short-term financing requirements are satisfied, as needed, through short-term bank loans and borrowings under other unsecured lines of credit maintained with banks. At December 31, 1993, short-term borrowings amounted to $155.8 million (see Note 5).

The KG&E common and preferred stock was redeemed in connection with the Merger, leaving 1,000 shares of common stock held by Western Resources. The debt structure of the Company and available sources of funds were not affected by the Merger.

RESULTS OF OPERATIONS

The following is an explanation of significant variations from prior year results in revenues, operating expenses, other income and deductions, and interest charges. Additional information relating to changes between years is provided in the Notes to Financial Statements.

Revenues: The operating revenues of the Company are based on sales volumes and rates, authorized by the Kansas Corporation Commission (KCC) and the FERC, charged for the sale and delivery of electricity. Rates are designed to recover the cost of service and allow investors a fair rate of return. Future electric sales will continue to be affected by weather conditions, competing fuel sources, customer conservation efforts and the overall economy of the Company's service area.

The KCC order approving the Merger provided a moratorium on increases, with certain exceptions, in the Company's electric rates until August 1995. The KCC ordered refunds totalling $32 million to the combined companies' (Western Resources and the Company) customers to share with customers the Merger-related cost savings achieved during the moratorium period. The first refund was made in April 1992 and amounted to approximately $4.9 million for the Company. A refund of approximately $4.9 million was made in December 1993 and an additional refund of approximately $8.7 million will be made in September 1994 (see Note 1).

On March 26, 1992, in connection with the Merger, the KCC approved the elimination of the Energy Cost Adjustment Clause (ECA) for most retail customers of the Company effective April 1, 1992. The fuel costs are now included in base rates and were established at a level intended by the KCC to equal the projected average cost of fuel through August 1995. Any increase or decrease in fuel costs from the projected average will be absorbed by the Company.

1993 COMPARED TO 1992: Total operating revenues increased $62.7 million or 11.3 percent in 1993 compared to 1992 pro forma revenues. The increase is due to the return of near normal temperatures during 1993 compared to unusually mild winter and summer temperatures in 1992. All customer classes experienced increased sales volumes during 1993. The number of cooling degree days recorded for the city of Wichita were 1,546 for 1993, a 23 percent increase from 1992. Contributing to the increase in wholesale sales were sales to neighboring utilities to meet peak demand periods while those utilities' units were down as a result of the summer flooding.

Partially offsetting these increases in revenues was the amortization of the Merger-related refund.

1992 COMPARED TO 1991: Pro forma operating revenues were $554 million in 1992, a 6.8 percent decrease from 1991. The decrease is a result of unusually mild temperatures during 1992 compared to 1991. Revenues from residential customers decreased 11.7 percent compared to 1991 primarily due to reduced air conditioning load. The Company experienced only 1,258 cooling degree days in Wichita in 1992, a 38.9 percent decrease from 1991 and a 22.7 percent decrease from normal weather. Commercial, industrial and wholesale revenues also reflected small decreases in 1992. Also decreasing revenues was the amortization of the Merger-related refund discussed previously.

Operating Expenses: 1993 COMPARED TO 1992: Total operating expenses increased $45.5 million or 10.7 percent in 1993 compared to 1992. Fuel, and purchased power expenses increased $21.4 million or 22.5 percent primarily due to increased generation resulting from increased customer demand for electricity during the summer peak season. Federal and state income taxes increased $28.6 million primarily as a result of higher net income. General taxes increased $4.8 million primarily due to an increase in plant, the property tax assessment ratio, and higher mill levies.

Partially offsetting these increases in total operating expenses was a decrease in other operations expense of $10.1 million primarily as a result of merger-related savings for the entire year of 1993 and reduced net lease expense for La Cygne 2 (see Note 7) compared to pro forma operating expenses of 1992.

At December 31, 1993, the Company completed the accelerated amortization of deferred income tax reserves related to the allowance for borrowed funds used during construction capitalized for Wolf Creek Generating Station. The amortization of these deferred income tax reserves amounted to approximately $12 million in 1993. In accordance with the provisions of the Merger order (see Note 1), the Company is precluded from recovering the $12 million annual amortization in rates until the next rate filing. Therefore the Company's earnings will be impacted negatively until these income taxes are recovered in future rates.

1992 COMPARED TO 1991: Pro forma operating expenses decreased $44.8 million or 9.6 percent in 1992 compared to 1991. Fossil fuel expenses decreased $23.3 million or 24.1 percent primarily due to decreased generation resulting from reduced demand for electricity during the summer peak season and decreased generation by natural gas-fired units with the availability of Wolf Creek. Merger-related cost savings, an early retirement plan, a voluntary separation program and unseasonable mild weather allowed other operating expenses to decrease $19.2 million. Maintenance expenses decreased $6.2 million primarily due to the scheduled major overhaul at La Cygne 2 during 1991.

Partially offsetting these decreases were higher nuclear fuel expenses of $4 million as a result of the increased availability of Wolf Creek in 1992 compared to 1991. Property taxes also increased as a result of increased plant and tax mill levies.

As permitted under the La Cygne 2 generating station lease agreement, in 1992, KG&E requested the Trustee Lessor to refinance $341.1 million of secured facility bonds of the Trustee and owner of La Cygne 2. The transaction was requested to reduce the Company's recurring future net lease expense. To accomplish this transaction, a one-time payment of approximately $27 million was made which will be amortized over the remaining life of the lease and will be included in operating expense as part of the future lower lease expense. On September 29, 1992 the Trustee Lessor refinanced bonds having a coupon rate of approximately 11.7% with bonds having a coupon rate of approximately 7.7%.

Expenses related to the merger with Western Resources were $1.1 million for the three months ended March 31, 1992. Other operations expense for 1991, included $3.8 for expenses related to the Company's response to the unsolicited tender offer by Kansas City Power & Light Company (KCPL) and the merger with Western Resources.

Other Income and Deductions: Other income and deductions, net of taxes, increased slightly in 1993 compared to 1992 due to the increased cash surrender values of COLI policies and the receipt of death benefit proceeds. Partially offsetting these increases was higher interest expense on COLI borrowings.

Pro forma other income and deductions, net of taxes, increased significantly for 1992 compared to 1991 as a result of increased cash surrender values of corporate-owned life insurance polices and the recognition of the recovery of $4.2 million of the previously written-off investment in Drexel Burnham Lambert Group Inc. (Drexel) commercial paper.

In April 1992, the Company completed the sale of its 80% interest in CIC Systems, Inc. (CIC). The Company had recorded a $1 million charge in 1991 representing the annual net loss incurred by CIC.

Interest Charges: Interest charges decreased $12.4 million in 1993 compared to 1992 as the Company continued to take advantage of lower interest rates on variable-rate and fixed-rate debt by retiring and refinancing higher cost debt. The Company's embedded cost of long-term debt decreased to 7.3% at December 31, 1993 compared to 7.5% and 7.9% at December 31, 1992 and 1991, respectively.

Pro forma interest charges decreased $3.3 million in 1992, primarily as a result of the refinancing of higher cost fixed-rate debt and lower interest rates on variable-rate debt.

OTHER INFORMATION

Inflation: Under the ratemaking procedures prescribed by the regulatory commissions to which the Company is subject, only the original cost of plant is recoverable in revenues as depreciation. Therefore, because of inflation, present and future depreciation provisions are inadequate for purposes of maintaining the purchasing power invested by common shareholders and the related cash flows are inadequate for replacing property. The impact of this ratemaking process on common shareholders is mitigated to the extent depreciable property is financed with debt that can be repaid with dollars of less purchasing power. While the Company has experienced relatively low inflation in the recent past, the cumulative effect of inflation on operating costs may require the Company to seek regulatory rate relief to recover these higher costs.

Environmental: The Company has recognized the importance of environmental responsibility and has taken a proactive position with respect to the potential environmental liability associated with former manufactured gas sites. The Company has an agreement with the Kansas Department of Health and Environment to systematically evaluate these sites in Kansas (see Note 3).

The Company currently has no Phase I affected units under the Clean Air Act of 1990. Until such time that additional regulations become final the Company will be unable to determine its compliance options or related compliance costs. (see Note 3).

Energy Policy Act: The 1992 Energy Policy Act (the Act) requires increased efficiency of energy usage and will potentially change the way electricity is marketed. The Act also provides for increased competition in the wholesale electric market by permitting the FERC to order third party access to utilities' transmission systems and by liberalizing the rules for ownership of generating facilities. As part of the Merger, the Company agreed to open access to its transmission system. Another part of the Act requires a special assessment to be collected from utilities for a uranium enrichment, decontamination, and decommissioning fund. The Company's portion of the assessment for Wolf Creek is approximately $7 million, payable over 15 years. Management expects such costs to be recovered through the ratemaking process.

Statement of Financial Accounting Standards No. 106 (SFAS 106) and No. 112 (SFAS 112): For discussion regarding the effect of SFAS 106 and SFAS 112 on the Company see Note 8 of the Notes to Financial Statements.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

TABLE OF CONTENTS

SCHEDULES OMITTED

The following schedules are omitted because of the absence of the conditions under which they are required or the information is included in the financial statements and schedules presented:

I, II, III, IV, VII, VIII, IX, X, XI, XII and XIII.

REPORT OF INDEPENDENT PUBLIC ACCOUNTANTS

To the Board of Directors of
Kansas Gas and Electric Company:

We have audited the accompanying balance sheet and statement of capitalization of Kansas Gas and Electric Company (a wholly-owned subsidiary of Western Resources, inc.) as of December 31, 1993, and the related statements of income, cash flows, taxes, and common stock equity for the year 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 audit.

We conducted our audit in accordance with generally accepted auditing standards. Those standards require that we plan and perform the audit to obtain reasonable assurance 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 audit provides 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 Kansas Gas and Electric Company as of December 31, 1993, and the results of its operations and its cash flows for the year then ended in conformity with generally accepted accounting principles.

As explained in Note 8 to the financial statements, effective January 1, 1993, the Company changed its method of accounting for postretirement benefits.

Our audit was made for the purpose of forming an opinion on the 1993 basic financial statements taken as a whole. The financial statement schedules listed in the table of contents on page 19 are presented for purposes of complying with the Securities and Exchange Commission's rules and are not part of the basic financial statements. These schedules for 1993 have been subjected to the auditing procedures applied in the audit of the basic financial statements and, in our opinion, fairly state in all material respects the financial data required to be set forth therein in relation to the basic financial statements taken as a whole.

Kansas City, Missouri, ARTHUR ANDERSEN & CO.
January 28, 1994

INDEPENDENT AUDITORS' REPORT

Kansas Gas and Electric Company:

We have audited the 1992 and 1991 financial statements of Kansas Gas and Electric Company (a wholly-owned subsidiary of Western Resources, Inc.) listed in the accompanying table of contents. Our audits also included the 1992 and 1991 financial statement schedules listed in the accompanying table of contents. These financial statements and financial statement schedules are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and financial statement schedules 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, such financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 1992 and the results of its operations and its cash flows for the periods indicated in conformity with generally accepted accounting principles. Also, in our opinion, such financial statement schedules, when considered in relation to the basic financial statements taken as a whole, present fairly in all material respects the information shown therein.

DELOITTE & TOUCHE

Kansas City, Missouri
January 29, 1993

KANSAS GAS AND ELECTRIC COMPANY
BALANCE SHEETS
(Thousands of Dollars)

	December 31, 1993	1992
ASSETS		
UTILITY PLANT:		
Electric plant in service (Notes 1, 6, and 12).	$3,339,832	$3,293,365
Less - Accumulated depreciation	790,843	724,188
	2,548,989	2,569,177
Construction work in progress	28,436	29,634
Nuclear fuel (net).	29,271	33,312
Net utility plant	2,606,696	2,632,123
OTHER PROPERTY AND INVESTMENTS:		
Decommissioning trust (Note 3).	13,204	9,272
Other	10,941	13,855
	24,145	23,127
CURRENT ASSETS:		
Cash and cash equivalents (Note 2).	63	892
Accounts receivable and unbilled revenues (net)(Note 6) .	11,112	10,543
Advances to parent company (Note 14).	192,792	74,289
Fossil fuel, at average cost, ...	7,594	16,101
Materials and supplies, at average cost	29,933	31,453
Prepayments and other current assets.	14,995	7,820
	256,489	141,098
DEFERRED CHARGES AND OTHER ASSETS:		
Deferred future income taxes (Note 9)	113,479	138,361
Deferred coal contract settlement costs (Note 4).	21,247	24,520
Phase-in revenues (Note 4).	78,950	96,495
Other deferred plant costs.	32,008	32,212
Corporate-owned life insurance (net) (Note 2)	45	144,547
Other	54,420	46,749
	300,149	482,884
TOTAL ASSETS	$3,187,479	$3,279,232
CAPITALIZATION AND LIABILITIES		
CAPITALIZATION (see statement).	$1,899,221	$2,009,227
CURRENT LIABILITIES:		
Short-term debt (Note 5).	155,800	93,500
Long-term debt due within one year (Note 6)	238	228
Accounts payable.	51,095	60,908
Accrued taxes	12,185	17,684
Accrued interest.	7,381	10,935
Other	9,427	5,963
	236,126	189,218
DEFERRED CREDITS AND OTHER LIABILITIES:		
Deferred income taxes (Notes 1 and 9)	646,159	671,196
Deferred investment tax credits (Note 9).	78,048	73,939
Deferred gain from sale-leaseback (Note 7).	261,981	271,621
Other	65,944	64,031
	1,052,132	1,080,787
COMMITMENTS AND CONTINGENCIES (Notes 3 and 10)		
TOTAL CAPITALIZATION AND LIABILITIES	$3,187,479	$3,279,232

The NOTES TO FINANCIAL STATEMENTS are an integral part of these statements.

KANSAS GAS AND ELECTRIC COMPANY
STATEMENTS OF INCOME
(Thousands of Dollars)

	Year Ended December 31,				
			1992		
	1993	Pro Forma 1992	April 1 to Dec. 31 (Successor)	January 1 to March 31 (Predecessor)	1991
OPERATING REVENUES (Notes 2 and 4). . . .	$ 616,997	$ 554,251	$ 423,538	$ 130,713	$ 594,968
OPERATING EXPENSES:					
Fuel used for generation:					
Fossil fuel	93,388	73,785	53,701	20,084	97,159
Nuclear fuel.	13,275	12,558	10,126	2,432	8,593
Power purchased	9,864	8,746	3,207	5,539	7,811
Other operations.	118,948	129,083	91,436	37,647	148,312
Maintenance	46,740	46,702	35,956	10,746	52,934
Depreciation and amortization	75,530	74,696	55,547	19,149	75,115
Amortization of phase-in revenues . . .	17,545	17,544	13,158	4,386	17,545
Taxes (see statement):					
Federal income.	39,553	16,305	17,523	(1,218)	17,569
State income	9,570	4,264	4,732	(468)	5,307
General	45,203	40,406	30,155	10,251	38,540
Total operating expenses.	469,616	424,089	315,541	108,548	468,885
OPERATING INCOME.	147,381	130,162	107,997	22,165	126,083
OTHER INCOME AND DEDUCTIONS:					
Investment income	629	1,367	953	414	3,147
Corporate-owned life insurance (net). .	7,841	10,724	9,308	1,416	4,615
Miscellaneous (net) (Note 3).	8,642	6,506	8,464	(1,958)	(12,844)
Income taxes (net) (see statement). . .	2,227	191	(1,296)	1,487	6,921
Total other income and deductions .	19,339	18,788	17,429	1,359	1,839
INCOME BEFORE INTEREST CHARGES.	166,720	148,950	125,426	23,524	127,922
INTEREST CHARGES:					
Long-term debt.	53,908	57,862	42,889	14,973	59,668
Other	6,075	15,121	11,777	3,344	17,838
Allowance for borrowed funds used during construction (credit)	(1,366)	(2,014)	(1,181)	(833)	(3,186)
Total interest charges.	58,617	70,969	53,485	17,484	74,320
NET INCOME.	108,103	77,981	71,941	6,040	53,602
PREFERRED DIVIDENDS	-	-	-	205	821
EARNINGS APPLICABLE TO COMMON STOCK . . .	$ 108,103	$ 77,981	$ 71,941	$ 5,835	$ 52,781

The NOTES TO FINANCIAL STATEMENTS are an integral part of these statements.

KANSAS GAS AND ELECTRIC COMPANY
STATEMENTS OF CASH FLOWS
(Thousands of Dollars)

	Year Ended December 31, 1993 (Successor)	1992 March 31 to Dec. 31 (Successor)	1992 January 1 to March 31 (Predecessor)	1991 (Predecessor)
CASH FLOWS FROM OPERATING ACTIVITIES:				
Net income	$ 108,103	$ 71,941	$ 6,040	$ 53,602
Depreciation and amortization	75,530	55,547	19,149	75,115
Other amortization (including nuclear fuel)	11,254	8,929	1,352	6,014
Deferred taxes and investment tax credits (net)	22,572	9,326	(2,851)	3,525
Amortization of phase-in revenues	17,545	13,158	4,386	17,545
Corporate-owned life insurance	(21,650)	(14,704)	(3,295)	(11,986)
Coal contract settlements (Note 4)	-	-	-	(8,500)
Amortization of gain from sale-leaseback	(9,640)	(7,231)	(2,409)	(9,641)
Changes in working capital items:				
Accounts receivable and unbilled revenues (net) (Note 2)	(569)	1,079	1,272	346
Fossil fuel	8,507	4,425	(1,858)	3,631
Accounts payable	(9,813)	(7,216)	(6,100)	15,421
Interest and taxes accrued	(9,053)	(14,345)	10,598	1,296
Other	(2,191)	(8,456)	1,689	(5,832)
Changes in other assets and liabilities	(16,530)	(41,401)	(5,479)	3,947
Net cash flows from operating activities	174,065	71,052	22,494	144,483
CASH FLOWS USED IN INVESTING ACTIVITIES:				
Additions to utility plant	66,886	53,138	11,496	74,348
Corporate-owned life insurance policies	27,268	20,233	6,802	27,349
Death proceeds of corporate-owned life insurance	(10,160)	(6,789)	-	-
Purchase of short-term investments	-	-	-	742
Proceeds from short-term investments	-	-	-	(22,097)
Other investments	-	-	(552)	1,142
Merger:				
Purchase of KG&E common stock-net of cash received	-	432,043	-	-
Purchase of KG&E preferred stock	-	19,665	-	-
Net cash flows used in investing activities	83,994	518,290	17,746	81,484
CASH FLOWS FROM (USED IN) FINANCING ACTIVITIES:				
Short-term debt (net)	62,300	49,900	5,800	7,800
Advances to parent company (net)	(118,503)	(74,289)	-	-
First mortgage bonds issued	65,000	135,000	-	323,406
First mortgage bonds retired	(140,000)	(125,000)	-	(57,000)
Other long-term debt (net)	7,043	14,498	(3,810)	(377,031)
Borrowings against life insurance policies (net)	183,260	(5,649)	6,398	3,590
Revolving credit agreement (net)	(150,000)	-	-	80,000
Special deposits (net)	-	-	-	13,263
Other (net)	-	-	(17)	31
Dividends on preferred and common stock	-	-	(13,535)	(54,143)
Financing expenses	-	-	-	(8,508)
Issuance of KCA common stock	-	453,670	-	-
Net cash flows from (used in) financing activities	(90,900)	448,130	(5,164)	(68,592)
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	(829)	892	(416)	(5,593)
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	892	-	2,378	7,971
CASH AND CASH EQUIVALENTS AT END OF PERIOD	$ 63	$ 892	$ 1,962	$ 2,378
SUPPLEMENTAL DISCLOSURES OF CASH FLOW INFORMATION				
CASH PAID FOR:				
Interest on financing activities (net of amount capitalized)	$ 77,653	$ 63,451	$ 11,635	$ 89,901
Income taxes	29,354	14,225	-	11,350

The NOTES TO FINANCIAL STATEMENTS are an integral part of these statements.

KANSAS GAS AND ELECTRIC COMPANY
STATEMENTS OF TAXES
(Thousands of Dollars)

	Year Ended December 31, 1993 (Successor)	1992 April 1 to Dec. 31 (Successor)	1992 January 1 to March 31 (Predecessor)	1991 (Predecessor)
FEDERAL INCOME TAXES:				
Payable currently	$ 19,220	$ 11,356	$ (322)	$ 11,023
Deferred (net)	16,691	8,633	(1,785)	64
Investment tax credit-Deferral	4,900	946	-	3,622
-Amortization	(3,114)	(2,400)	(777)	(2,913)
Total Federal income taxes	37,697	18,535	(2,884)	11,796
Income taxes applicable to non-operating items	1,856	(1,012)	1,666	5,773
Total Federal income taxes charged to operations	39,553	17,523	(1,218)	17,569
STATE INCOME TAXES:				
Payable currently	5,104	2,869	-	1,407
Deferred (net)	4,095	2,147	(289)	2,752
Total state income taxes	9,199	5,016	(289)	4,159
Income taxes applicable to non-operating items	371	(284)	(179)	1,148
Total state income taxes charged to operations	9,570	4,732	(468)	5,307
GENERAL TAXES:				
Property	38,432	26,380	8,622	32,755
Payroll and other taxes	6,771	3,775	1,629	5,785
Total general taxes charged to operations	45,203	30,155	10,251	38,540
TOTAL TAXES CHARGED TO OPERATIONS	$ 94,326	$ 52,410	$ 8,565	$ 61,416

	Year Ended December 31, 1993 (Successor)	Pro Forma 1992	1991 (Predecessor)
EFFECTIVE INCOME TAX RATE	30%	21%	23%
Effect of:			
Additional depreciation	(3)	(4)	(8)
Accelerated amortization of deferred income tax credits	8	11	15
State income taxes, net of Federal benefit	(4)	(2)	(4)
Amortization of investment tax credits	2	2	4
Corporate-owned life insurance	5	6	6
Other items (net)	(3)	-	(2)
STATUTORY FEDERAL INCOME TAX RATE	35%	34%	34%

The NOTES TO FINANCIAL STATEMENTS are an integral part of these statements.

KANSAS GAS AND ELECTRIC COMPANY
STATEMENTS OF CAPITALIZATION
(Thousands of Dollars)

	Due	1993	1992	December 31, 1993	%	1992	%
COMMON STOCK EQUITY (Note 1):							
(see statement)							
Common stock, without par value, authorized and issued 1,000 shares.				$1,065,634	56.1%	$1,065,634	53.0%
Retained earnings				180,044	9.5	71,941	3.6
Total common stock equity				1,245,678	65.6	1,137,575	56.6
LONG-TERM DEBT (Note 6):							
First Mortgage Bonds:							
Series	Due	1993	1992				
5-5/8%	1996	$ 16,000	$ 16,000				
8-1/8%	2001	-	35,000				
7-3/8%	2002	-	25,000				
7.6%	2003	135,000	135,000				
6-1/2%	2005	65,000	-				
8-3/8%	2006	-	25,000				
8-1/2%	2007	-	25,000				
8-7/8%	2008	-	30,000				
				216,000		291,000	
Pollution Control Bonds:							
6.80%	2004	14,500	14,500				
5-7/8%	2007	21,940	21,940				
6%	2007	10,000	10,000				
7.0%	2031	327,500	327,500				
				373,940		373,940	
Total bonds.				589,940		664,940	
Other Long-Term Debt:							
Pollution control obligations:							
5-3/4% series	2003	13,980	14,205				
Revolving credit agreement	1993	-	150,000				
Other long-term agreement	1995	53,913	46,640				
Total other long-term debt				67,893		210,845	
Unamortized premium and discount (net).				(4,052)		(3,905)	
Long-term debt due within one year.				(238)		(228)	
Total long-term debt				653,543	34.4	871,652	43.4
TOTAL CAPITALIZATION.				$1,899,221	100.0%	$2,009,227	100.0%

The NOTES TO FINANCIAL STATEMENTS are an integral part of these statements.

KANSAS GAS AND ELECTRIC COMPANY
STATEMENTS OF COMMON STOCK EQUITY
(Thousands of Dollars, Except Shares)
Years Ended December 31,

	Common Stock Shares	Common Stock Amount	Other Paid-in Capital	Retained Earnings	Treasury Stock Shares	Treasury Stock Amount	Total
BALANCE DECEMBER 31, 1990. . (Predecessor)	40,996,185	$ 636,986	$ 270	$171,139	(9,996,426)	(199,255)	$ 609,140
Net income				53,602			53,602
Cash dividends:							
Common stock				(53,322)			(53,322)
Preferred stock.				(821)			(821)
Employee stock plans . . .	1,560	17	14				31
BALANCE DECEMBER 31, 1991. . (Predecessor)	40,997,745	637,003	284	170,598	(9,996,426)	(199,255)	608,630
Net income				6,040			6,040
Cash dividends:							
Common stock				(13,330)			(13,330)
Preferred stock.				(205)			(205)
Employee stock plans . . .		(12)			(966)		(12)
Merger of KG&E with KCA. .	(40,997,745)	(636,991)	(284)	(163,103)	9,997,392	199,255	(601,123)
BALANCE MARCH 31, 1992 (Predecessor).	-0-	-0-	-0-	-0-	-0-	-0-	-0-
KCA common stock issued. .	1,000	$1,065,634	-	-	-	-	$1,065,634
Net income				$ 71,941			71,941
BALANCE DECEMBER 31, 1992. . (Successor)	1,000	1,065,634	-	71,941	-	-	1,137,575
Net income				108,103			108,103
BALANCE DECEMBER 31, 1993. .	1,000	$1,065,634	$ -	$ 180,044	-	$ -	$1,245,678

The NOTES TO FINANCIAL STATEMENTS are an integral part of these statements.

KANSAS GAS AND ELECTRIC COMPANY
NOTES TO FINANCIAL STATEMENTS

1. ACQUISITION AND MERGER

On March 31, 1992, Western Resources, Inc. (formerly The Kansas Power and Light Company) (Western Resources) through its wholly-owned subsidiary KCA Corporation (KCA), acquired all of the outstanding common and preferred stock of Kansas Gas and Electric Company (KG&E) for $454 million in cash and 23,479,380 shares of Western Resources common stock (the Merger). Western Resources also paid $20 million in costs to complete the Merger. The total cost of the acquisition to Western Resources was $1.066 billion. Simultaneously, KCA and KG&E merged and adopted the name of Kansas Gas and Electric Company. The Merger was accounted for as a purchase. For income tax purposes the tax basis of the Company's assets was not changed by the Merger. In the accompanying statements, KG&E prior to the Merger is labeled as the "Predecessor" and after the Merger as the "Successor". Throughout the notes to financial statements, the "Company, KG&E" refers to both Predecessor and Successor.

As Western Resources acquired 100% of the common and preferred stock of KG&E, the Company recorded an acquisition premium of $490 million on the balance sheet for the difference in purchase price and book value and increased common stock equity to reflect the new cost basis of Western Resources' investment in the Company. This acquisition premium and related income tax requirement of $294 million under Statement of Financial Accounting Standards No. 109 (SFAS 109) have been classified as plant acquisition adjustment in electric plant in service on the balance sheets. Under the provisions of the order of the Kansas Corporation Commission (KCC), the acquisition premium is recorded as an acquisition adjustment and not allocated to the other assets and liabilities of the Company.

The pro forma information for the year ended December 31, 1992 in the accompanying financial statements gives effect to the Merger as if it occurred on January 1, 1992, and was derived by combining the historical information for the three month period ended March 31, 1992 and the nine month period ended December 31, 1992. No purchase accounting adjustments were made for periods prior to the Merger in determining pro forma amounts, other than the elimination of preferred dividends, because such adjustments would be immaterial. This pro forma information is not necessarily indicative of the results of operations that would have occurred had the Merger been consummated on January 1, 1992, nor is it necessarily indicative of future operating results or financial position. The pro forma effects on the Company's net income for 1991 presented giving effect to the Merger as if it had occurred at the beginning of the earliest period presented would not be materially different from that shown in the income statements included herein.

In the November 1991 KCC order approving the Merger, a mechanism was approved to share equally between the shareholders and ratepayers the cost savings generated by the Merger in excess of the revenue requirement needed to allow recovery of the amortization of a portion of the acquisition adjustment, including income tax, calculated on the basis of a purchase price of KG&E's common stock at $29.50 per share. The order provides an amortization period for the acquisition adjustment of 40 years commencing in August 1995, at which time the full amount of cost savings is expected to have been implemented. Merger savings will be measured by application of an inflation index to certain pre-merger operating and maintenance costs at the time of the next Kansas rate case. While the Company has achieved savings from the Merger, there is no assurance that the savings achieved will be sufficient to, or the cost savings sharing mechanism will operate as to fully offset the amortization of the acquisition adjustment. The order further provides a moratorium on increases, with certain exceptions, in the Company's Kansas electric rates until August 1995. The KCC ordered refunds totalling $32 million to the combined companies' (Western Resources and the Company) customers to share with customers the Merger-related cost savings achieved during the moratorium period. The first refund was made in April 1992 and amounted to approximately $4.9 million for the Company. A refund of approximately $4.9 million was made in December 1993 and an additional refund of approximately $8.7 million will be made in September 1994.

The KCC order approving the Merger requires the legal reorganization of the Company so that it is no longer held as a separate subsidiary after January 1, 1995, unless good cause is shown why such separate existence should be maintained. The Securities and Exchange Commission order relating to the Merger granted Western Resources an exemption under the Public Utilities Holding Company Act until January 1, 1995. In connection with a requested ruling that a merger of the Company into Western Resources would not adversely affect the tax structure of the merger, the Company received a response from the Internal Revenue Service that the IRS would not issue the requested ruling. In light of the IRS response, the Company withdrew its request for a ruling. The Company will consider alternative forms of combination or seek regulatory approvals to waive the requirements for a combination. There is no certainty as to whether a combination will occur or as to the form or timing thereof.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

General: The financial statements of KG&E include, through March 31, 1992, its 80% owned subsidiary, CIC Systems, Inc. (CIC). In April 1992, the Company disposed of its 80% interest in CIC. KG&E owns 47 percent of Wolf Creek Nuclear Operating Corporation (WCNOC), the operating company for Wolf Creek Generating Station (Wolf Creek). The Company records its proportionate share of all transactions of WCNOC as it does other jointly-owned facilities. The accounting policies of the Company are in accordance with generally accepted accounting principles as applied to regulated public utilities. The accounting and rates of the Company are subject to requirements of the KCC and the Federal Energy Regulatory Commission (FERC).

Utility Plant: Utility plant (including plant acquisition adjustment) is stated at cost. For constructed plant, cost includes contracted services, direct labor and materials, indirect charges for engineering, supervision, general and administrative costs, and an allowance for funds used during construction (AFUDC). The AFUDC rate was 4.41% for 1993, 6.51% for the nine months ended December 31, 1992, 6.70% for the three months ended March 31, 1992, and 7.74% for 1991. The cost of additions to utility plant and replacement units of property is capitalized. Maintenance costs and replacement of minor items of property are charged to expense as incurred.

When units of depreciable property are retired, they are removed from the plant accounts and the original cost plus removal charges less salvage are charged to accumulated depreciation.

Depreciation: Depreciation is provided on the straight-line method based on estimated useful lives of property. Composite provisions for book depreciation approximated 2.9% during 1993, 2.9% during the nine months ended December 31, 1992, 3.0% during the three months ended March 31, 1992, and 3.0% during 1991 of the average original cost of depreciable property.

Cash and Cash Equivalents: For purposes of the Statements of Cash Flows, cash and cash equivalents include cash on hand and highly liquid collateralized debt instruments purchased with maturities of three months or less.

Income Taxes: Income tax expense includes provisions for income taxes currently payable and deferred income taxes calculated in conformance with income tax laws, regulatory orders and Statement of Financial Accounting Standards No. 109 (SFAS 109) (see Note 9).

Investment tax credits are deferred as realized and amortized to income over the life of the property which gave rise to the credits.

Revenues: Operating revenues include amounts actually billed for services rendered and an accrual of estimated unbilled revenues. Unbilled revenues represent the estimated amount customers will be billed for service provided from the time meters were last read to the end of the accounting period. Unbilled revenues of $22.3 and $16.6 million at December 31, 1993 and 1992, respectively, are recorded as a component of accounts receivable on the balance sheets. Certain amounts of unbilled revenues have been sold (see Note 6).

The Company had reserves for doubtful accounts receivable of $3.0 and $2.4 million at December 31, 1993 and 1992, respectively.

Fuel Costs: The cost of nuclear fuel in process of refinement, conversion, enrichment and fabrication is recorded as an asset at original cost and is amortized to expense based upon the quantity of heat produced for the generation of electricity. The accumulated amortization of nuclear fuel in the reactor at December 31, 1993 and 1992 was $17.4 and $26.0 million, respectively.

Cash Surrender Value of Life Insurance Contracts: The following amounts related to corporate-owned life insurance contracts (COLI), primarily with one highly rated major insurance company, are recorded on the balance sheets (millions of dollars):

	1993	1992
Cash surrender value of contracts. . .	$269.1	$230.3
Prepaid COLI	9.5	4.8
Borrowings against contracts	(269.0)	(85.8)
COLI (net)	$ 9.6	$149.3

The decrease in COLI (net) is a result of increased borrowings against the accumulated cash surrender value of the COLI policies. The COLI borrowings will be repaid with proceeds from death benefits. Management expects to realize increases in cash surrender value of contracts resulting from premiums and investment earnings on a tax free basis upon receipt of net proceeds from death benefits under the contracts. Interest expense included in corporate-owned life insurance (net) on the statements of income was $11.9 million for 1993, $5.3 million for the nine months ended December 31, 1992, $1.9 million for the three months ended March 31, 1992, and $7.3 for 1991.

As approved by the Kansas Corporation Commission (KCC), the Company is using a portion of the net income stream generated by COLI policies purchased in 1993 and 1992 (see Note 8) to offset Statement of Financial Accounting Standards No. 106 (SFAS 106) expenses.

Reclassifications: Certain amounts in prior years have been reclassified to conform with classifications used in the current year presentation.

3. COMMITMENTS AND CONTINGENCIES

Environmental: The Company and the Kansas Department of Health and Environment entered into a consent agreement to perform preliminary assessments of six former manufactured gas sites. The preliminary assessments of these sites have been completed at minimal cost. Until such time that risk assessments are completed at these sites, it will be impossible to predict the cost of remediation. However, the Company is aware of other utilities in Region VII of the EPA (Kansas, Missouri, Nebraska, and Iowa) which have incurred remediation costs for such sites ranging between $500,000 and $10 million, depending on the site. The Company is also aware that the KCC has permitted another Kansas utility to recover a portion of the remediation costs through rates. To the extent that such remediation costs are not recovered through rates, the costs could be material to the Company's financial position or results of operations depending on the degree of remediation and number of years over which the remediation must be completed.

Spent Nuclear Fuel Disposal: Under the Nuclear Waste Policy Act of 1982, the U.S. Department of Energy (DOE) is responsible for the ultimate storage and disposal of spent nuclear fuel removed from nuclear reactors. Under a contract with the DOE for disposal of spent nuclear fuel, the Company pays a quarterly fee to DOE of one mill per kilowatthour of net nuclear generation. These fees are included as part of nuclear fuel expense and amounted to $3.5 million for 1993, $1.6 million for the nine months ended December 31, 1992, $.5 million for the three months ended March 31, 1992, and $2.8 million for 1991.

Decommissioning: The Company's share of Wolf Creek decommissioning costs, currently authorized in rates, was estimated to be approximately $97 million in 1988 dollars. Decommissioning costs are being charged to operating expenses. Amounts so expensed are deposited in an external trust fund and will be used solely for the physical decommissioning of the plant. Electric rates charged to customers provide for recovery of these decommissioning costs over the estimated life of Wolf Creek. At December 31, 1993 and 1992, $13.2 and $9.3 million respectively, were on deposit in the decommissioning fund. On September 1, 1993, WCNOC filed an application with the KCC for an order approving a 1993 Wolf Creek Decommissioning Cost Study which estimates the

Company's share of Wolf Creek decommissioning costs at approximately $174 million in 1993 dollars. If approved by the KCC, management expects substantially all such cost increases to be recovered through the ratemaking process.

The Company carries $164 million in premature decommissioning insurance in the event of a shortfall in the trust fund. The insurance coverage has several restrictions. One of these is that it can only be used if Wolf Creek incurs an accident exceeding $500 million in expenses to safely stabilize the reactor, to decontaminate the reactor and reactor station site in accordance with a plan approved by the Nuclear Regulatory Commission (NRC), and to pay for on-site property damages. If the amount designated as decommissioning insurance is needed to implement the NRC-approved plan for stabilization and decontamination, it would not be available for decommissioning purposes.

Nuclear Insurance: The Price-Anderson Act limits the combined public liability of the owners of nuclear power plants to $9.4 billion for a single nuclear incident. The Wolf Creek owners (Owners) have purchased the maximum available private insurance of $200 million and the balance is provided by an assessment plan mandated by the NRC. Under this plan, the Owners are jointly and severally subject to a retrospective assessment of up to $79.3 million ($37.3 million, Company's share) in the event there is a nuclear incident involving any of the nation's licensed reactors. This assessment is subject to an inflation adjustment based on the Consumer Price Index. There is a limitation of $10 million ($4.7 million, Company's share) in retrospective assessments per incident per year.

The Owners carry decontamination liability, premature decommissioning liability, and property damage insurance for Wolf Creek totalling approximately $2.8 billion ($1.3 billion, Company's share). This insurance is provided by a combination of "nuclear insurance pools" ($1.3 billion) and Nuclear Electric Insurance Limited (NEIL) ($1.5 billion). In the event of an accident, insurance proceeds must first be used for reactor stabilization and site decontamination. The remaining proceeds from the $2.8 billion insurance coverage ($1.3 billion, Company's share), if any, can be used for property damage up to $1.1 billion (Company's share) and premature decommissioning costs up to $117.5 million (Company's share) in excess of funds previously collected for decommissioning (as discussed under "Decommissioning"), with the remaining $47 million (Company's share) available for either property damage or premature decommissioning costs.

The Owners also carry additional insurance with NEIL to cover costs of replacement power and other extra expenses incurred during a prolonged outage resulting from accidental property damage at Wolf Creek. If losses incurred at any of the nuclear plants insured under the NEIL policies exceed premiums, reserves, and other NEIL resources, the Company may be subject to retrospective assessments of approximately $9 million per year.

There can be no assurance that all potential losses or liabilities will be insurable or that the amount of insurance will be sufficient to cover them. Any substantial losses not covered by insurance, to the extent not recoverable through rates, could have a material adverse effect on the Company's financial position and results of operations.

Clean Air Act: The Clean Air Act Amendments of 1990 (the Act) require a two-phase reduction in sulfur dioxide and nitrogen oxide emissions effective in 1995 and 2000 and a probable reduction in toxic emissions. To meet the monitoring and reporting requirements under the acid rain program, the Company is installing continuous monitoring and reporting equipment at a total cost of approximately $2.3 million. At December 31, 1993, the Company had completed approximately $850 thousand of these capital expenditures with the remaining $1.4 million of capital expenditures to be completed in 1994 and 1995. The Company does not expect additional equipment to reduce sulfur emissions to be necessary under Phase II. The Company currently has no Phase I affected units.

The nitrogen oxide and toxic limits, which were not set in the law, will be specified in future EPA regulations. The EPA has issued for public comment preliminary nitrogen oxide regulations for Phase I group 1 units. Nitrogen oxide regulations for Phase II units and Phase I group 2 units are mandated in the Act to be promulgated by January 1, 1997. Although the Company has no Phase I units, the final nitrogen oxide regulations for Phase I group 1 may allow for early compliance for Phase II group 1 units. Until such time as the Phase I group 1 nitrogen oxide regulations are final, the Company will be unable to determine its compliance options or related compliance costs.

Federal Income Taxes: During 1991, the Internal Revenue Service (IRS) completed an examination of the Company's federal income tax returns for the years 1984 through 1988. In April 1992, the Company received the examination report and upon review filed a written protest in August 1992. In October 1993, the Company received another examination report for the years 1989 and 1990 covering the same issues identified in the previous examination report. Upon review of this report, the Company filed a written protest in November 1993. The most significant proposed adjustments reduce the depreciable basis of certain assets and investment tax credits generated. Management believes there are significant questions regarding the theory, computations, and sampling techniques used by the IRS to arrive at its proposed adjustments, and also believes any additional tax expense incurred or loss of investment tax credits will not be material to the Company's financial position and results of operations. Additional income tax payments, if any, are expected to be offset by investment tax credit carryforwards, alternative minimum tax credit carryforwards, or deferred tax provisions.

Other Investments: In prior years, the Company routinely purchased short-term investment grade commercial paper for special deposit interest accounts associated with tax-exempt pollution control bonds. On February 1, 1990, the Company purchased $6.6 million of Drexel Burnham Lambert Group Inc. (Drexel) commercial paper. On February 13, 1990, Drexel filed for bankruptcy. In 1990, additional claims being filed and potential lengthy litigation indicated full recovery would be unlikely; accordingly, the investment was written off in 1990. The Company recognized the recovery of approximately $4.2 million during the nine months ended December 31, 1992, of the investment, which is included in miscellaneous income.

Fuel Commitments: To supply a portion of the fuel requirements for its generating plants, the Company has entered into various commitments to obtain nuclear fuel, coal, and natural gas. Some of these contracts contain provisions for price escalation and minimum purchase commitments. At December 31, 1993, WCNOC's nuclear fuel commitments (Company's share) were approximately $18.0 million for uranium concentrates expiring at various times through 1997, $123.6 million for enrichment expiring at various times through 2014, and $45.5 million for fabrication through 2012. At December 31, 1993, the Company's coal and natural gas contract commitments in 1993 dollars under the remaining term of the contracts are $666 million and $20.4 million, respectively. The largest coal contract was renegotiated in early 1993 and expires in 2020 with the remaining coal contracts expiring at various times through 2013. The majority of natural gas contracts expire in 1995 with automatic one-year extension provisions. In the normal course of business, additional commitments and spot market purchases will be made to obtain adequate fuel supplies.

Energy Act: As part of the 1992 Energy Policy Act, a special assessment is being collected from utilities for a uranium enrichment decontamination and decommissioning fund. The Company's portion of the assessment for Wolf Creek is approximately $7 million, payable over 15 years. Management expects such costs to be recovered through the ratemaking process.

4. RATE MATTERS AND REGULATION

Elimination of the Energy Cost Adjustment Clause (ECA): On March 26, 1992, in connection with the Merger, the KCC approved the elimination of the ECA for most retail customers effective April 1, 1992. The provisions for fuel costs included in base rates were established at a level intended by the KCC to equal the projected average cost of fuel through August 1995, and to include recovery of costs provided by previously issued orders relating to coal contract settlements and storm damage recovery discussed below. Any increase or decrease in fuel costs from the projected average will be absorbed by the Company.

Rate Stabilization Plan: In 1988, the KCC issued an order requiring that the accrual of phase-in revenues be discontinued effective December 31, 1988. Effective January 1, 1989, the Company began amortizing the phase-in revenue asset on a straight-line basis over 9-1/2 years.

Cost of Service Audit Appeal: In September 1991, the KCC ordered the Company to refund (which the Company has done) $5.6 million of revenues plus $0.6 million in interest, for the period July 2, 1990 through January 31, 1991. This order concluded the appeal of the February 1990 KCC order to reduce rates by $8.7 million. The Company had previously recorded reserves totalling $10.8 million; however, as the order also made rates permanent, the excess reserves of $3.3 million were reversed in September 1991.

Coal Contract Settlements: In March 1990, the KCC issued an order allowing the Company to defer its share of a 1989 coal contract settlement with the Pittsburg and Midway Coal Mining Company amounting to $22.5 million. This amount was recorded as a deferred charge on the balance sheets. The settlement resulted in the termination of a long-term coal contract. In June 1991, the KCC permitted the Company to recover this settlement as follows: 76% of the settlement plus a return over the remaining term of the terminated contract (through 2002) and 24% to be amortized to expense with a deferred return equivalent to the carrying cost of the asset.

In February 1991, the Company paid $8.5 million to settle a coal contract lawsuit with AMAX Coal Company and recorded the payment as a deferred charge on the Company's balance sheet. In July 1991, the KCC approved the recovery of the settlement plus a return equivalent to the carrying cost of the asset, over the remaining term of the terminated contract (through 1996).

Storm Damage Recovery: In October 1990, the Company asked the KCC for approval of a plan to recover the cost of damage primarily from the March 13 and June 19, 1990 storms. Approximately $15 million of capital expenditures were incurred. These costs have been included in the Company's electric plant accounts. In May 1991, the Company amended this request to include the estimated $5 million of capital expenditures associated with an April 1991 storm. In November 1991 and January 1992, the KCC approved the deferral and recovery of the capital expenditures of the 1990 and 1991 storms, respectively, as well as carrying charges thereon.

5. SHORT-TERM BORROWINGS

At December 31, 1993, the Company had bank credit arrangements available of $35 million. In addition, the Company has uncommitted loan participation agreements. Maximum short-term borrowings outstanding during 1993 and 1992 were $175.8 million on December 14, 1993 and $128 million on October 6, 1992. The weighted average interest rates, including fees, were 3.5% for 1993, 6.4% for the nine months ended December 31, 1992, 7.1% for the three months ended March 31, 1992, and 7.8% for 1991.

6. LONG-TERM DEBT

The amount of first mortgage bonds authorized by the KG&E Mortgage and Deed of Trust (Mortgage) dated April 1, 1940, as supplemented, is limited to a maximum of $2 billion. Amounts of additional bonds which may be issued are subject to property, earnings, and certain restrictive provisions of the Mortgage. Electric plant is subject to the lien of the Mortgage except for transportation equipment. During 1993, the Company refinanced $65 million of first mortgage bonds by issuing $65 million of First Mortgage Bonds, 6 1/2% Series due 2005. In 1992, the Company refinanced $125 million of first mortgage bonds by issuing $135 million of First Mortgage Bonds, 7.6% Series due 2003.

Debt discount and expenses are being amortized over the remaining lives of each issue. The improvement and maintenance fund requirements for certain first mortgage bond series can be met by bonding additional property. The sinking fund requirements for certain pollution control series bonds can be met only through the acquisition and retirement of outstanding bonds.

The 6.80% series, due 2004, the 6% and 5 7/8% series due 2007 and the 7% series due 2031 are pledged as collateral for pollution control revenue bonds issued by Kansas municipalities.

On September 20, 1993, the Company terminated a long-term revolving credit agreement which provided for borrowings of up to $150 million. The loan agreement, which was effective through October 1994, was repaid without penalty. The weighted average interest rate, including fees, was 3.7% for 1993, 6.8% for the nine months ended December 31, 1992, 7.7% for the three months ended March 31, 1992, and 8.4% for 1991.

The Company has a long-term agreement, expiring in 1995, which contains provisions for the sale of accounts receivable and unbilled revenues (receivables) and phase-in revenues up to a total of $180 million. Amounts related to receivables are accounted for as sales while those related to phase-in revenues are accounted for as collateralized borrowings. Additional receivables are continually sold to replace those collected. At December 31, 1993 and 1992, outstanding receivables amounting to $56.8 and $47.7 million, respectively, were considered sold under the agreement. The credit risk associated with the sale of customer accounts receivable is considered minimal. The weighted average interest rate, including fees, on this agreement was 3.7% for 1993, 6.6% for the nine months ended December 31, 1992, 7.9% for the three months ended March 31, 1992, and 7.8% for 1991. At December 31, 1993, an additional $16.4 million was available under the agreement.

Bonds maturing and acquisition and retirement of bonds for sinking fund requirements for the five years subsequent to December 31, 1993 are as follows:

Year	Maturing Bonds	Retiring Bonds
	(Dollars in Thousands)	
1994.	$ -	$ 238
1995.	-	253
1996.	16,000	270
1997.	-	833
1998.	-	1,050

7. SALE-LEASEBACK OF LA CYGNE 2

In 1987, the Company sold and leased back its 50 percent undivided interest in La Cygne 2 generating unit. The lease has an initial term of 29 years, with various options to renew the lease or repurchase the 50 percent undivided interest. The Company remains responsible for its share of operation and maintenance costs and other related operating costs of La Cygne 2. The lease is an operating lease for financial reporting purposes.

As permitted under the lease agreement, the Company in 1992 requested the Trustee Lessor to refinance $341.1 million of secured facility bonds of the Trustee and owner of La Cygne 2. The transaction was requested to reduce recurring future net lease expense. In connection with the refinancing on September 29, 1992, a one-time payment of approximately $27 million was made by the Company which has been deferred and is being amortized over the remaining life of the lease and included in operating expense as part of the future lease expense.

Future minimum annual lease payments required under the lease agreement are approximately $34.6 million for each year through 1998 and $715 million over the remainder of the lease.

The gain of approximately $322 million realized at the date of the sale has been deferred for financial reporting purposes, and is being amortized over the initial lease term in proportion to the related lease expense. The Company's lease expense, net of amortization of the deferred gain and a one-time payment, was approximately $22.5 million for 1993, $20.6 million for the nine months ended December 31, 1992, $7.5 million for the three months ended March 31, 1992, and $30 million for 1991.

8. EMPLOYEE BENEFIT PLANS

Pension: The Company maintains noncontributory defined benefit pension plans covering substantially all employees of the Company prior to the Merger. Pension benefits are based on years of service and the employee's compensation during the five highest paid consecutive years out of ten before retirement. The Company's policy is to fund pension costs accrued, subject to limitations set by the Employee Retirement Income Security Act of 1974 and the Internal Revenue Code.

The following table provides information on the components of pension cost for the Company's pension plans (millions of dollars):

	1993 (Successor)	1992 April 1 to Dec.31 (Successor)	1992 Jan.1 to March 31 (Predecessor)	1991 (Predecessor)
Pension Cost:				
Service cost	$ 3.2	$ 2.5	$ .8	$ 3.1
Interest cost on projected benefit obligation	9.5	6.7	2.1	7.4
Return on plan assets.	(14.1)	(5.8)	(9.0)	(14.0)
Net amortization & deferral. . . .	4.9	(1.0)	6.7	5.4
Net pension cost	$ 3.5	$ 2.4	$ .6	$ 1.9

The following table sets forth the plans' actuarial present value and funded status at November 30, 1993 and 1992 (the plan years) and a reconciliation of such status to the December 31, 1993 and 1992 financial statements (millions of dollars):

	1993	1992
Funded Status:		
Actuarial present value of benefit obligations:		
Vested.	$ 95.2	$ 82.9
Non-vested.	6.1	3.6
Total	$101.3	$ 86.5
Plan assets at November 30 (principally debt and equity securities) at fair value.	$119.9	$113.7
Projected benefit obligation at November 30 . . .	(125.5)	(110.8)
Plan assets in excess of projected benefit obligation at November 30	(5.6)	2.9
Unrecognized transition asset	(1.7)	(2.0)
Unrecognized prior service costs.	12.4	12.1
Unrecognized net gain	(20.6)	(26.1)
Accrued pension costs at December 31.	$(15.5)	$(13.1)

Year Ended December 31,	1993	1992
Actuarial Assumptions:		
Discount rate	7.0-7.75%	8.0-8.5%
Annual salary increase rate	5.0 %	6.0%
Long-term rate of return.	8.0-8.5 %	8.0-8.5%

Early Retirement and Voluntary Separation Plans: In January 1992, the Board of Directors approved an early retirement plan and a voluntary separation program. The voluntary early retirement plan was offered to all vested participants of the Company's defined benefit pension plan who reached the age of 55 with 10 or more years of service on or before May 1, 1992. Certain pension plan improvements were made including a waiver of the actuarial reduction factors for early retirement and a cash incentive payable as a monthly supplement up to 60 months or a lump sum payment. Of the 111 employees eligible for the early retirement option, 71, representing 6% of the Company's work force, elected to retire on or before the May 1, 1992, deadline. Another 29 employees, with 10 or more years of service, elected to participate in the voluntary separation program. In addition, 61 employees received Merger-related severance benefits. The actuarial cost, based on plan provisions for early retirement and voluntary separation programs, and Merger-related severance benefits, was approximately $3.9 million of which $1.8 million was included in the pension liability at December 31, 1992. The actuarial cost was considered in purchase accounting for the Merger (See Note 1).

Postretirement: The Company adopted the provisions of Statement of Financial Accounting Standards No. 106 (SFAS 106) in the first quarter of 1993. This statement requires the accrual of postretirement benefits other than pensions, primarily medical benefits costs, during the years an employee provides service.

Based on actuarial projections and adoption of the transition method of implementation which allows a 20-year amortization of the accumulated benefit obligation, the annual expense under SFAS 106 was approximately $3.4 million in 1993 (as compared to approximately $1.8 million on a cash basis) and the Company's total obligation was approximately $23.9 million at December 31, 1993. To mitigate the impact of SFAS 106 expense, the Company has implemented programs to reduce health care costs. In addition, the Company has received an order from the KCC permitting the initial deferral of SFAS 106 expense. To mitigate the impact SFAS 106 expense will have on rate increases, the Company will include in the future computation of cost of service the actual SFAS 106 expense and an income stream generated from corporate-owned life insurance policies (COLI) purchased in 1993 and 1992. To the extent SFAS 106 expense exceeds income from the COLI program, this excess will be deferred (as allowed by FASB Emerging Issues Task Force Issue No. 92-12) and offset by income generated through the deferral period by the COLI program. Should the income stream generated by the COLI program not be sufficient to offset the deferred SFAS 106 expense, the KCC order allows recovery of such deficit through the ratemaking process.

Prior to the adoption of SFAS 106 the Company's policy was to recognize expenses as claims were paid. The costs of benefits were $0.8 million for the nine months ended December 31, 1992, $0.2 million for the three months ended March 31, 1992, and $2.1 million for 1991.

The following table summarizes the status of the Company's postretirement plans for financial statement purposes and the related amount included in the balance sheet:

December 31,	1993
	(Dollars in Millions)
Actuarial present value of postretirement benefit obligations:	
Retirees	$ 12.4
Active employees fully eligible	2.5
Active employees not fully eligible	9.0
Unrecognized prior service cost	(.1)
Unrecognized transition obligation	(20.4)
Unrecognized net loss	(1.7)
Balance sheet liability	$ 1.7

For measurement purposes, an annual health care cost growth rate of 13% was assumed for 1994, decreasing to 6% by 2002 and thereafter. The accumulated post retirement benefit obligation was calculated using a weighted-average discount rate of 7.75%, a weighted-average compensation increase rate of 5.0%, and a weighted-average expected rate of return of 8.5%. The health care cost trend rate has a significant effect on the projected benefit obligation. Increasing the trend rate by 1% each year would increase the present value of the accumulated projected benefit obligation by $.6 million and the aggregate of the service and interest cost components by $.1 million.

Postemployment: The FASB has issued Statement of Financial Accounting Standards No. 112 (SFAS 112), which establishes accounting and reporting standards for postemployment benefits. The new statement will require the Company to recognize the liability to provide postemployment benefits when the liability has been incurred. The Company adopted SFAS 112 effective January 1, 1994. To mitigate the impact adopting SFAS 112 will have on rate increases, the Company will file an application with the KCC for an order permitting the initial deferral of SFAS 112 transition costs and expenses and its inclusion in the future computation of cost of service net of an income stream generated from COLI. At December 31, 1993, the Company estimates SFAS 112 liability to total approximately $700,000.

Savings Plans: The Company maintains 401(k) savings plans in which substantially all employees participate. The Company matches employees' contributions up to a maximum limit of 3 percent of the employees' salary. Prior to the Merger, the Company's matching contribution was based on the Company's performance during the prior year and the level of employee contributions. The funds of the plans are deposited with a trustee and invested at each employee's option in one or more investment funds, including a Western Resources common stock fund. The Company's contributions were $1.3 for 1993, $1.7 million for the nine months ended December 31, 1992, $0.2 million for the three months ended March 31, 1992, and $2.0 million for 1991.

9. INCOME TAXES

The Company adopted Statement of Financial Accounting Standards No. 96 (SFAS 96) in 1987. This statement required the Company to establish deferred tax assets and liabilities, as appropriate, for all temporary differences, and to adjust deferred tax balances to reflect changes in tax rates expected to be in effect during the periods the temporary differences reverse. SFAS 96 was superseded by SFAS 109 issued in February 1992 and the Company adopted the provisions of that standard prospectively in the first quarter of 1992. The accounting for SFAS 109 is substantially the same as SFAS 96.

In accordance with various rate orders received from the KCC, the Company has not yet collected through rates the amounts necessary to pay a significant portion of the net deferred income tax liabilities. As management believes it is probable that the net future increases in income taxes payable will be recovered from customers through future rates, it has recorded a deferred asset for these amounts. These assets are also a temporary difference for which deferred income tax liabilities have been provided. Accordingly, the adoption of SFAS 109 did not have a material effect on the Company's results of operations.

At December 31, 1993, the Company had unused investment tax credits of approximately $7.1 million available for carryforward which, if not utilized, will expire in the years 2000 through 2002 (see Note 3). In addition, the Company has alternative minimum tax credits generated prior to April 1, 1992, which carryforward without expiration, of $53.9 million which may be used to offset future regular tax to the extent the regular tax exceeds the alternative minimum tax. These credits have been applied in determining the Company's net deferred income tax liability and corresponding deferred future income taxes at December 31, 1993.

Beginning April 1, 1992, the Company is part of the consolidated income tax return of Western Resources. However, the Company determines its income tax provisions on a separate company basis.

Deferred income taxes result from temporary differences between the financial statement and tax basis of the Company's assets and liabilities. The sources of these differences and their cumulative tax effects are as follows:

December 31,	1993		
	Debits	Credits	Total
	(Dollars in Thousands)		
Sources of Deferred Income Taxes:			
Accelerated depreciation and other property items	$ -	$ (350,105)	$ (350,105)
Energy and purchased gas adjustment clauses	3,257	-	3,257
Phase-in revenues.	-	(35,573)	(35,573)
Deferred gain on sale-leaseback. .	116,186	-	116,186
Alternative minimum tax credits. .	39,882	-	39,882
Deferred coal contract settlements.	-	(7,797)	(7,797)
Deferred compensation/pension liability.	10,856	-	10,856
Acquisition premium.	-	(300,814)	(300,814)
Deferred future income taxes . . .	-	(109,178)	(109,178)
Other.	-	(12,873)	(12,873)
Total Deferred Income Taxes.	$ 170,181	$ (816,340)	$ (646,159)

December 31,	1992		
	Debits	Credits	Total
	(Dollars in Thousands)		
Sources of Deferred Income Taxes:			
Accelerated depreciation and other property items	$ -	$ (324,972)	$ (324,972)
Energy and purchased gas adjustment clauses	2,691	-	2,691
Phase-in revenues.	-	(37,564)	(37,564)
Deferred gain on sale-leaseback. .	104,573	-	104,573
Alternative minimum tax credits. .	39,882	-	39,882
Deferred coal contract settlements.	-	(9,263)	(9,263)
Deferred compensation/pension liability.	11,002	-	11,002
Acquisition premium.	-	(313,721)	(313,721)
Deferred future income taxes . . .	-	(146,962)	(146,962)
Other.	3,138	-	3,138
Total Deferred Income Taxes.	$ 161,286	$ (832,482)	$ (671,196)

10. LEGAL PROCEEDINGS

The Company is involved in various other legal and environmental proceedings. Management believes that adequate provision has been made within the financial statements for these matters and accordingly believes their ultimate dispositions will not have a material adverse effect upon the financial position or results of operations of the Company.

A provision of $12 million was recorded in miscellaneous expenses on the 1991 statement of income with respect to various legal matters.

11. FAIR VALUE OF FINANCIAL INSTRUMENTS

The following methods and assumptions were used to estimate the fair value of each class of financial instruments for which it is practicable to estimate that value as set forth in Statement of Financial Accounting Standards No. 107:

Cash and Cash Equivalents-
The carrying amount approximates the fair value because of the short-term maturity of these investments.

Decommissioning Trust-
The fair value of the decommissioning trust is based on quoted market prices at December 31, 1993 and 1992.

Variable-rate Debt-
The carrying amount approximates the fair value because of the short-term variable rates of these debt instruments.

Fixed-rate Debt-
The fair value of the fixed-rate debt is based on the sum of the estimated value of each issue taking into consideration the coupon rate, maturity, and redemption provisions of each issue.

The estimated fair values of the Company's financial instruments are as follows:

	Carrying Value		Fair Value	
December 31,	1993	1992	1993	1992
	(Dollars in Thousands)			
Cash and cash equivalents.	$ 63	$ 892	$ 63	$ 892
Decommissioning trust. . .	13,204	9,272	13,929	9,500
Variable-rate debt	478,743	375,909	478,743	375,909
Fixed-rate debt.	603,920	679,145	660,750	705,970

12. JOINT OWNERSHIP OF UTILITY PLANTS

	Company's Ownership at December 31, 1993				
	In-Service Dates	Invest-ment	Accumulated Depreciation	Net (MW)	Per-cent
		(Dollars in Thousands)			
La Cygne 1 (a)	Jun 1973	$ 150,265	$ 91,175	342	50
Jeffrey 1 (b)	Jul 1978	65,803	28,717	140	20
Jeffrey 2 (b)	May 1980	64,375	25,552	135	20
Jeffrey 3 (b)	May 1983	95,336	31,084	140	20
Wolf Creek (c)	Sep 1985	1,366,387	281,819	533	47

(a) Jointly owned with Kansas City Power & Light Company (KCP&L)
(b) Jointly owned with Western Resources, UtiliCorp United Inc., and a third party
(c) Jointly owned with KCPL and Kansas Electric Power Cooperative, Inc.

Amounts and capacity represent the Company's share. The Company's share of operating expenses of the plants in service above, as well as such expenses for a 50 percent undivided interest in La Cygne 2 (representing 335 MW capacity) sold and leased back to the Company in 1987, are included in operating expenses in the statements of income. The Company's share of other transactions associated with the plants is included in the appropriate classification in the Company's financial statements.

13. QUARTERLY FINANCIAL STATISTICS (Unaudited)
(Dollars in Thousands)

The amounts in the table are unaudited but, in the opinion of management, contain all adjustments (consisting only of normal recurring adjustments) necessary for a fair presentation of the results of such periods. The business of the Company is seasonal in nature and, in the opinion of management, comparisons between the quarters of a year do not give a true indication of overall trends and changes in operations.

	1993			
	4th Qtr.	3rd Qtr.	2nd Qtr.	1st. Qtr.
	(Successor)			
Operating revenues.	$136,097	$191,941	$150,478	$138,481
Operating income.	26,188	52,874	35,545	32,774
Net income.	13,692	46,406	24,274	23,731
Earnings applicable to common stock	13,692	46,406	24,274	23,731

	1992			
	4th Qtr.	3rd Qtr.	2nd Qtr.	1st. Qtr.
	(Successor)			(Predecessor)
Operating revenues.	$127,058	$167,825	$128,655	$130,713
Operating income.	29,282	49,541	29,174	22,165
Net income.	15,528	35,987	20,426	6,040
Earnings applicable to common stock	15,528	35,987	20,426	5,835

14. RELATED PARTY TRANSACTIONS

Subsequent to the Merger, the cash management function, including cash receipts and disbursements, for KG&E has been assumed by Western Resources. As a result, the proceeds of cash collections, including short-term borrowings, less disbursements related to KG&E transactions have been recorded by the Companies through an intercompany account which, at December 31, 1993, resulted in a net advance by KG&E to Western Resources of $192.8 million. Certain of the Company's operating expenses have been allocated from Western Resources. These expenses are allocated, depending on the nature of the expense, based on allocation studies, net investment, number of customers, and/or other appropriate allocators. Management believes such allocation procedures are reasonable.

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

There were no disagreements with accountants on accounting and financial disclosure. Information relating to a change in accountants is incorporated by reference from the Company's Current Report on Form 8-K dated March 8, 1993.

PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

Western Resources, Inc. owns 100 percent of the Company's outstanding common stock.

Name	Age	Business Experience Since 1988 and Other Directorships Other Than The Company	A Director Continuously Since
Kent R. Brown	48	Chairman of the Board, President and Chief Executive Officer since June 1992, and prior to that President and Chief Executive Officer since March 1992, and prior to that Group Vice President Directorships Bank IV Wichita	1992
Robert T. Crain (a)	68	Owner, Crain Realty, Co., Fort Scott, Kansas Directorships Citizens National Bank	1992(b)
Anderson E. Jackson	60	President, Jackson Mortuary, Wichita, Kansas	1994
Donald A. Johnston (a)	60	President, Maupintour, Inc., Lawrence, Kansas (Escorted Tours and Travel) Directorships Commerce Bank, Lawrence Maupintour, Inc.	1992(b)
Steven L. Kitchen	48	Executive Vice President and Chief Financial Officer, Western Resources, Inc., (since March 1990) and prior to that Senior Vice President, Finance and Accounting (October 1987 to March 1990)	1992
Glenn L. Koester	68	Retired Vice President - Nuclear of the Company	1992(b)
James J. Noone (a)	73	Attorney and retired Administrative Judge for the District Court of Sedgwick County, Kansas	1992(b)
Marilyn B. Pauly	44	President, Bank IV Wichita, Wichita, Kansas Directorships St. Francis Regional Medical Center Farmers Mutual Alliance Insurance Company	1994

Name	Age	Business Experience Since 1988 and Other Directorships Other Than The Company	A Director Continuously Since
Newton C. Smith	72	Physician and Surgeon, Arkansas City, Kansas	1992(b)
Richard Smith	60	President, Range Oil Company Directorships Bank IV Kansas Wichita HCA Wesley Medical Center	1993

(a) Member of the Audit Committee of which Mr. Johnston is Chairman. The Audit Committee has responsibility for the investigation and review of the financial affairs of the Company and its relations with independent accountants.
(b) Mr. Crain, Mr. Johnston, Mr. Koester, Mr. Noone, and Mr. Newton Smith were directors of the former Kansas Gas & Electric Company since 1981, 1980, 1986, 1986, and 1985, respectively.

Outside Directors are paid $3,750 per quarter retainer and all Directors are paid an attendance fee of $600 for Directors' meetings ($300 if attending by phone) and $500 for committee meetings. An additional committee meeting attendance fee of $800 is paid to the outside Director Audit Committee Chairman, and $500 to other outside Committee members. All outside Directors are reimbursed mileage and expenses while attending Directors' and Committee Meetings.

The Board of Directors held 5 meetings during the year and the Audit Committee held 2 meetings. All Directors attended 75% or more of their applicable meetings.

Other information required by Item 10 is omitted pursuant to General Instruction J(2)(c) to Form 10-K.

ITEM 11. EXECUTIVE COMPENSATION

Information required by Item 11 is omitted pursuant to General Instruction J(2)(c) to Form 10-K.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

Information required by Item 12 is omitted pursuant to General Instruction J(2)(c) to Form 10-K.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

Information required by Item 13 is omitted pursuant to General Instruction J(2)(c) to Form 10-K.

PART IV

ITEM 14. EXHIBITS, FINANCIAL STATEMENT SCHEDULES, AND REPORTS ON FORM 8-K

The following financial statements are included herein under Item 8.

FINANCIAL STATEMENTS

Balance Sheets, December 31, 1993 and 1992
Statements of Income for the year ended December 31, 1993 (Successor), the nine months ended December 31, 1992 (Successor), the three months ended March 31, 1992 (Predecessor), and the year ended December 31, 1991 (Predecessor)
Statements of Cash Flows for the year ended December 31, 1993 (Successor), the period March 31 to December 31, 1992 (Successor), the three months ended March 31, 1992 (Predecessor), and the year ended December 31, 1991 (Predecessor)
Statements of Taxes for the year ended December 31, 1993 (Successor), the nine months ended December 31, 1992 (Successor), the three months ended March 31, 1992 (Predecessor), and the year ended December 31, 1991 (Predecessor)
Statements of Capitalization, December 31, 1993 and 1992
Statements of Common Stock Equity for the year ended December 31, 1993 (Successor), the nine months ended December 31, 1992 (Successor), the three months ended March 31, 1992 (Predecessor), and the year ended December 31, 1991 (Predecessor)
Notes to Financial Statements

The following supplemental schedules are included herein.

SCHEDULES

Schedule V - Utility Plant for the year ended December 31, 1993, (Successor), the nine months ended December 31, 1992 (Successor), the three months ended March 31, 1992 (Predecessor), and the year ended December 31, 1991 (Predecessor)
Schedule VI - Accumulated Depreciation of Utility Plant for the year ended December 31, 1993 (Successor), the nine months ended December 31, 1992 (Successor) the three months ended March 31, 1992 (Predecessor), and the year ended December 31, 1991 (Predecessor)

REPORTS ON FORM 8-K

Form 8-K dated January 31, 1994

EXHIBIT INDEX

All exhibits marked "I" are incorporated herein by reference.

	Description	
2(a)	Agreement and Plan of Merger (Filed as Exhibit 2 to Form 10-K for the year ended December 31, 1990, File No. 1-7324).	I
2(b)	Amendment No. 1 to Agreement and Plan of Merger (Filed as Exhibit 2 to Form 10-K for the year ended December 31, 1990, File No. 1-7324).	I
3(a)	Articles of Incorporation (Filed as Exhibit 3(a) to Form 10-K for the year ended December 31, 1992, File No. 1-7324)	I
3(b)	Certificate of Merger of Kansas Gas and Electric Company into KCA Corporation (Filed as Exhibit 3(b) to Form 10-K for the year ended December 31, 1992, File No. 1-7324)	I
3(c)	By-laws as amended (Filed as Exhibit 3(c) to Form 10-K for the year ended December 31, 1992, File No. 1-7324)	I
4(c)1	Mortgage and Deed of Trust, dated as of April 1, 1940 to Guaranty Trust Company of New York (now Morgan Guaranty Trust Company of New York) and Henry A. Theis (to whom W. A. Spooner is successor), Trustees, as supplemented by thirty-six Supplemental Indentures, dated as of June 1, 1942, March 1, 1948, December 1, 1949, June 1, 1952, October 1, 1953, March 1, 1955, February 1, 1956, January 1, 1961, May 1, 1966, March 1, 1970, May 1, 1971, March 1, 1972, May 31, 1973, July 1, 1975, December 1, 1975, September 1, 1976, March 1, 1977, May 1, 1977, August 1, 1977, March 15, 1978, January 1, 1979, April 1, 1980, July 1, 1980, August 1, 1980, June 1, 1981, December 1, 1981, May 1, 1982, March 15, 1984, September 1, 1984 (Twenty-ninth and Thirtieth), February 1, 1985, April 15, 1986, June 1, 1991 March 31, 1992, December 17, 1992, and August 24, 1993, (Filed, respectively, as Exhibit A-1 to Form U-1, File No. 70-23; Exhibits 7(b) and 7(c), File No. 2-7405; Exhibit 7(d), File No. 2-8242; Exhibit 4(c), File No. 2-9626; Exhibit 4(c), File No. 2-10465; Exhibit 4(c), File No. 2-12228; Exhibit 4(c), File No. 2-15851; Exhibit 2(b)-1, File No. 2-24680; Exhibit 2(c), File No. 2-36170; Exhibits 2(c) and 2(d), File No. 2-39975; Exhibit 2(d), File No. 2-43053; Exhibit 4(c)2 to Form 10-K, for December 31, 1989, File No. 1-7324; Exhibit 2(c), File No. 2-53765; Exhibit 2(e), File No. 2-55488; Exhibit 2(c), File No. 2-57013; Exhibit 2(c), File No. 2-58180; Exhibit 4(c)3 to Form 10-K for December 31, 1989, File No. 1-7324; Exhibit 2(e), File No. 2-60089; Exhibit 2(c), File No. 2-60777; Exhibit 2(g), File No. 2-64521; Exhibit 2(h), File No. 2-66758; Exhibits 2(d) and 2(e), File No. 2-69620; Exhibits 4(d) and 4(e), File No. 2-75634; Exhibit 4(d), File No. 2-78944; Exhibit 4(d), File No. 2-87532; Exhibits 4(c)4, 4(c)5 and 4(c)6 to Form 10-K for December 31, 1989, File No. 1-7324; Exhibits 4(c)2 and 4(c)3 to Form 10-K for	I

Description

	December 31, 1992, File No. 1-7324; Exhibit 4(b) to Form S-3, File No. 33-50075)	
4(c)2	Thirty-seventh Supplemental Indenture dated as of January 15, 1994, to the Company's Mortgage and Deed of Trust (Filed electronically)	
4(c)3	Thirty-eighth Supplemental Indenture dated as of March 1, 1994, to the Company's Mortgage and Deed of Trust (Filed electronically)	

Instruments defining the rights of holders of other long-term debt not required to be filed as exhibits will be furnished to the Commission upon request.

10(a)1	Severance Agreement (Filed as Exhibit 10(a)1 to Form 10-K for the year ended December 31, 1990, File No. 1-7324).	I
10(a)2	Severance Agreement (Filed as Exhibit 10(a)2 to Form 10-K for the year ended December 31, 1990, File No. 1-7324).	I
10(a)3	Severance Agreement (Filed as Exhibit 10(a)3 to Form 10-K for the year ended December 31, 1990, File No. 1-7324).	I
10(b)	La Cygne 2 Lease (Filed as Exhibit 10(a) to Form 10-K for the year ended December 31, 1988, File No. 1-7324).	I
10(b)1	Amendment No. 3 to La Cygne 2 Lease Agreement dated as of September 29, 1992. (Filed as Exhibit 10(b)1 to Form 10-K for the year ended December 31, 1992, File No. 1-7324)	I
10(c)	Outside Directors' Deferred Compensation Plan	
12	Computation of Ratio of Consolidated Earnings to Fixed Charges. (Filed electronically)	
16	Letter re Change in Certifying Accountant. (Filed as Exhibit 16 to the Current Report on Form 8-K dated March 8, 1993.	I
23(a)	Consent of Independent Public Accountants, Arthur Andersen & Co. (Filed electronically)	
23(b)	Consent of Independent Public Accountants, Deloitte & Touche (Filed electronically)	

KANSAS GAS AND ELECTRIC COMPANY

Schedule V - Utility Plant

(Successor)

Classification	Balance at Beginning of Period	Additions at Cost	Retire- ments	Transfers, Reclassi- fications	Balance at End of Period
	(Thousands of Dollars)				
For the Year Ended December 31, 1993					
Electric Plant:					
Steam Production.	$ 469,258	$ 26,648	$ 2,710	$ -	$ 493,196
Nuclear Production.	1,355,678	11,324	614	-	1,366,388
Transmission.	215,898	1,422	141	-	217,179
Distribution.	371,714	19,630	1,872	-	389,472
General	62,110	6,839	1,846	-	67,103
Electric Plant Leased to Others .	6,984	-	-	-	6,984
Construction Work in Progress . .	29,634	(1,198)	-	-	28,436
Electric Plant Held for Future Use	15,458	5	129	-	15,334
Nuclear Fuel.	59,305	6,764	19,381	-	46,688
Plant Acquisition Adjustment. . .	796,265	-	-	(12,089)	784,176
	$3,382,304	$ 71,434	$ 26,693	$ (12,089)	$3,414,956

KANSAS GAS AND ELECTRIC COMPANY

Schedule V - Utility Plant

Classification	Balance at Beginning of Period	Additions at Cost	Retire- ments	Transfers, Reclassi- fications	Balance at End of Period
	(Thousands of Dollars)				
(Pro Forma) (2)					
For the Year Ended December 31, 1992					
Electric Plant:					
Steam Production.	$ 463,198	$ 8,420	$ 2,354	$ (6)	$ 469,258
Nuclear Production.	1,358,428	4,283	7,033	-	1,355,678
Transmission.	213,928	2,328	358	-	215,898
Distribution.	357,486	15,764	1,536	-	371,714
General	62,295	1,933	762	(1,356)	62,110
Electric Plant Leased to Others .	6,984	-	-	-	6,984
Construction Work in Progress . .	13,612	16,024	-	(2)	29,634
Electric Plant Held for Future Use	15,433	-	-	25	15,458
Nuclear Fuel.	42,731	16,661	-	(87)	59,305
Plant Acquisition Adjustment. . .	-	796,265(1)	-	-	796,265
	$2,534,095	$861,678	$12,043	$ (1,426)	$3,382,304
(Successor)					
For the Nine Months Ended December 31, 1992					
Electric Plant:					
Steam Production.	$ 468,032	$ 3,034	$ 1,808	$ -	$ 469,258
Nuclear Production.	1,358,833	3,505	6,660	-	1,355,678
Transmission.	213,898	2,220	220	-	215,898
Distribution.	359,223	13,531	1,040	-	371,714
General	61,007	1,799	696	-	62,110
Electric Plant Leased to Others .	6,984	-	-	-	6,984
Construction Work in Progress . .	15,744	13,892	-	(2)	29,634
Electric Plant Held for Future Use	15,458	-	-	-	15,458
Nuclear Fuel.	43,456	15,936	-	(87)	59,305
Plant Acquisition Adjustment. . .	-	796,265(1)	-	-	796,265
	$2,542,635	$850,182	$10,424	$ (89)	$3,382,304
(Predecessor)					
For the Three Months Ended March 31, 1992					
Electric Plant:					
Steam Production.	$ 463,198	$ 5,386	$ 546	$ (6)	$ 468,032
Nuclear Production.	1,358,428	778	373	-	1,358,833
Transmission.	213,928	108	138	-	213,898
Distribution.	357,486	2,233	496	-	359,223
General	62,295	134	66	(1,356)	61,007
Electric Plant Leased to Others .	6,984	-	-	-	6,984
Construction Work in Progress . .	13,612	2,132	-	-	15,744
Electric Plant Held for Future Use	15,433	-	-	25	15,458
Nuclear Fuel.	42,731	725	-	-	43,456
	$2,534,095	$11,496	$ 1,619	$ (1,337)	$2,542,635

(1) See Note 1 of Notes to the Financial Statements for explanation of plant acquisition adjustment.
(2) The pro forma information for the year ended December 31, 1992 was derived by combining the historical information of the three month period ended March 31, 1992 (Predecessor) and the nine month period ended December 31, 1992 (Successor). No purchase accounting adjustments were made for periods prior to the Merger in determining pro forma amounts because such adjustments would be immaterial.

KANSAS GAS AND ELECTRIC COMPANY

Schedule V - Utility Plant

(Predecessor)

Classification	Balance at Beginning of Period	Additions at Cost	Retire-ments	Transfers, Reclassi-fications	Balance at End of Period
	(Thousands of Dollars)				
For the Year Ended December 31, 1991					
Electric Plant:					
Steam Production.	$ 450,753	$13,746	$ 1,300	$ (1)	$ 463,198
Nuclear Production.	1,363,312	11,032	15,916	-	1,358,428
Transmission.	208,705	6,356	1,129	(4)	213,928
Distribution.	340,458	19,206	2,178	-	357,486
General	58,353	5,286	1,342	(2)	62,295
Electric Plant Leased to Others .	6,980	-	-	4	6,984
Construction Work in Progress . .	14,760	(1,148)	-	-	13,612
Electric Plant Held for Future Use	15,370	88	28	3	15,433
Nuclear Fuel.	28,152	19,782	5,203	-	42,731
	$2,486,843	$74,348	$27,096	$ -	$2,534,095

KANSAS GAS AND ELECTRIC COMPANY

Schedule VI - Accumulated Depreciation of Utility Plant

(Successor)

Description	Balance at Beginning of Period	Additions Charged to Costs and Expenses	Retire- ments	Other Charges	Balance at End of Period
	(Thousands of Dollars)				
For the Year Ended December 31, 1993					
Electric Plant:					
Steam Production.	$242,596	$16,486	$ 3,159	$ -	$255,923
Nuclear Production.	247,370	35,465	832	31	282,034
Transmission.	74,167	5,244	20	-	79,391
Distribution.	120,897	11,324	2,449	-	129,772
General	29,100	4,576	1,359	1,260	33,577
Electric Plant Leased to Others .	1,239	174	-		1,413
Electric Plant Held for Future Use	8,819	-	86	-	8,733
Nuclear Fuel.	25,993	10,805	19,381	-	17,417
	$750,181	$84,074	$27,286	$1,291	$808,260

KANSAS GAS AND ELECTRIC COMPANY

Schedule VI - Accumulated Depreciation of Utility Plant

Description	Balance at Beginning of Period	Additions Charged to Costs and Expenses	Retire-ments	Other Charges	Balance at End of Period
	(Thousands of Dollars)				
(Pro Forma) (1)					
For the Year Ended December 31, 1992					
Electric Plant:					
Steam Production.	$228,538	$16,433	$ 2,374	$ (1)	$242,596
Nuclear Production.	219,311	35,361	7,302	-	247,370
Transmission.	69,355	5,199	387	-	74,167
Distribution.	111,961	10,835	1,899	-	120,897
General	25,003	4,369	745	473	29,100
Electric Plant Leased to Others .	1,065	174	-	-	1,239
Electric Plant Held for Future Use	8,793	-	-	26	8,819
Nuclear Fuel.	16,132	9,850	-	11	25,993
	$680,158	$82,221	$12,707	$ 509	$750,181
(Successor)					
For the Nine Months Ended December 31, 1992					
Electric Plant:					
Steam Production.	$232,589	$11,942	$ 1,935	$ -	$242,596
Nuclear Production.	227,819	26,438	6,887	-	247,370
Transmission.	70,547	3,960	340	-	74,167
Distribution.	114,153	8,113	1,369	-	120,897
General	26,211	3,147	695	437	29,100
Electric Plant Leased to Others .	1,109	130	-	-	1,239
Electric Plant Held for Future Use	8,819	-	-	-	8,819
Nuclear Fuel.	17,377	8,605	-	11	25,993
	$698,624	$62,335	$11,226	$ 448	$750,181
(Predecessor)					
For the Three Months Ended March 31, 1992					
Electric Plant:					
Steam Production.	$228,538	$ 4,491	$ 439	$ (1)	$232,589
Nuclear Production.	219,311	8,923	415	-	227,819
Transmission.	69,355	1,239	47	-	70,547
Distribution.	111,961	2,722	530	-	114,153
General	25,003	1,222	50	36	26,211
Electric Plant Leased to Others .	1,065	44	-	-	1,109
Electric Plant Held for Future Use	8,793	-	-	26	8,819
Nuclear Fuel.	16,132	1,245	-	-	17,377
	$680,158	$19,886	$ 1,481	$ 61	$698,624

(1) The pro forma information for the year ended December 31, 1992 was derived by combining the historical information of the three month period ended March 31, 1992 (Predecessor) and the nine month period ended December 31, 1992 (Successor). No purchase accounting adjustments were made for periods prior to the Merger in determining pro forma amounts because such adjustments would be immaterial.

KANSAS GAS AND ELECTRIC COMPANY

Schedule VI - Accumulated Depreciation of Utility Plant

(Predecessor)

Description	Balance at Beginning of Period	Additions Charged to Costs and Expenses	Retire-ments	Other Charges	Balance at End of Period
	(Thousands of Dollars)				
For the Year Ended December 31, 1991					
Electric Plant:					
Steam Production.	$212,421	$17,305	$ 1,207	$ 19	$228,538
Nuclear Production.	199,938	35,460	16,087	-	219,311
Transmission.	65,463	5,107	1,215	-	69,355
Distribution.	104,043	10,396	2,478	-	111,961
General	21,582	4,127	1,278	572	25,003
Electric Plant Leased to Others .	891	174	-	-	1,065
Electric Plant Held for Future Use	8,841	-	29	(19)	8,793
Nuclear Fuel.	15,607	5,728	5,203	-	16,132
	$628,786	$78,297	$27,497	$ 572	$680,158

SIGNATURE

Pursuant to the requirements of Sections 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

KANSAS GAS AND ELECTRIC COMPANY

March 18, 1994 By KENT R. BROWN
(Kent R. Brown, Chairman of the Board,
President and Chief Executive Officer)

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934 this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated:

Signature	Title	Date
KENT R. BROWN (Kent R. Brown)	Chairman of the Board, President and Chief Executive Officer (Principal Executive Officer)	March 18, 1994
RICHARD D. TERRILL (Richard D. Terrill)	Secretary, Treasurer and General Counsel (Principal Financial and Accounting Officer)	March 18, 1994
ROBERT T. CRAIN (Robert T. Crain)		
(Anderson E. Jackson)		
DONALD A. JOHNSTON (Donald A. Johnston)		
S. L. KITCHEN (S. L. Kitchen)	Directors	March 18, 1994
GLENN L. KOESTER (Glenn L. Koester)		
JAMES J. NOONE (James J. Noone)		
(Marilyn B. Pauly)		
NEWTON C. SMITH, M.D. (Newton C. Smith, M. D.)		
RICHARD SMITH (Richard Smith)		