TU ELECTRIC

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William J. Cahill, Jr.
Group Vice President

April 8, 1992

U. S. Nuclea· Regulatory Commission
Attn: Document Control Desk
Washington, D.C. 20555

SUBJECT: COMANCHE PEAK STEAM ELECTRIC STATION (CPSES)
DOCKETS NO. 50-445 AND 50-446
SUBMITTAL OF ANNUAL REPORT FORM 10K

Gentlemen:

Pursuant to 10CFR50.71(b) TU Electric hereby submits five (5) copies of the Annual Report Form 10K.

Sincerely,

William J. Cahill, Jr.

By: DRWoodlan
D. R. Woodlan
Docket Licensing Manager

JDR/

Enclosures

c - Mr. R. D. Martin, Region IV, w/o enclosures
Resident Inspectors, CPSES, w/o enclosures

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FINAL

SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

Form 10-K

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

For the Fiscal Year Ended December 31, 1991

OR

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

Commission File Number 0-11442

Texas Utilities Electric Company

(Exact name of registrant as specified in its charter)

A Texas Corporation

I.R.S. Employer No. 75-1837355

2001 Bryan Tower, Dallas, Texas 75201
Telephone Number (214) 812-4600

Securities Registered Pursuant to Section 12(b) of the Act: None

Securities Registered Pursuant to Section 12 g) of the Act: Preferred Stock, without par value

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

Aggregate market value of Common Stock on February 28, 1992 held by non-affiliates: None

Common Stock outstanding at February 28, 1992: 141,125,000 shares, without par value

DOCUMENTS INCORPORATED BY REFERENCE

None

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PART I

Item 1. BUSINESS.

THE COMPANY

Texas Utilities Electric Company (Company) was incorporated under the laws of the State of Texas in 1982 and has perpetual existence under the provisions of the Texas Business Corporation Act. The Company is an electric utility engaged in the generation, purchase, transmission, distribution and sale of electric energy wholly within the State of Texas. The Company possesses all of the necessary franchises and certificates required to enable it to conduct its business (see Regulation and Rates).

The Company is the principal subsidiary of Texas Utilities Company (Texas Utilities). Texas Utilities also has three other subsidiaries which perform specialized services for the Texas Utilities Company System (System Companies), including the Company: Texas Utilities Fuel Company (Fuel Company) owns a natural gas pipeline system, acquires, stores and delivers fuel gas and provides other fuel services at cost for the generation of electric energy by the Company; Texas Utilities Mining Company (Mining Company) owns, leases and operates fuel production facilities for the surface mining and recovery of lignite at cost for use at the Company's generating stations; and Texas Utilities Services Inc. (TU Services) provides financial, accounting, computer, telecommunications and other administrative services at cost. TU Services also acts as transfer agent, registrar and dividend paying agent with respect to the preferred stock of the Company.

The Company's service area covers the north central, eastern and western parts of Texas, with a population estimated at 5,500,000 — about one-third of the population of Texas. Electric service is provided in 87 counties and 372 incorporated municipalities, including Dallas, Fort Worth, Midland, Odessa, Wichita Falls, Arlington, Irving, Plano, Mesquite, Richardson, Waco, Tyler and Killeen. The area is a diversified commercial and industrial center with substantial banking, insurance, electronics, aerospace, petrochemical and specialized steel manufacturing, and automotive and aircraft assembly. The territory served includes major portions of the oil and gas fields in the Permian Basin and East Texas, as well as substantial farming and ranching sections of the State. It also includes the Dallas-Fort Worth International Airport, Alliance Airport and the site of the Superconducting Super Collider. For energy sales and operating revenues contributed by each class of service, see Item 6, Selected Financial Data — Operating Statistics.

At December 31, 1991, the Company had 11,738 full-time employees.

PEAK LOAD AND CAPABILITY

The Company's net capability, peak load and reserve, in megawatts (MW), at the time of peak were as follows during the years indicated:

		Peak Load (a)			
Year	Net Capability	Amount	Increase Over Prior Year	Firm Peak Load (b)	Reserve(c)
1991	21,849	16 952	(5.9)%	16,831	5,018
1990	21,949	18,007	5.0	17,795	4,154
1989	20,448	17,146	(2.7)	16,944	3,504

(a) The Company peak load includes interruptible load at the time of peak of 341 MW in 1991, 347 MW in 1990 and 202 MW in 1989.

(b) The Company firm peak load excludes interruptible load at the time of system peak and includes 220 MW in 1991 and 135 MW in 1990 of load associated with certain wholesale customers who were purchasing non-firm energy from sources other than the Company.

(c) Amount of net capability in excess of firm peak load at the time of peak.

The peak load changes for 1991 and 1990 resulted primarily from weather factors in the service area and from customer growth. The peak load in 1991 oc-urred on August 8. Included in the 199: net capability was 1,921 MW of firm purchased capacity, including 1,841 MW of cogeneration and small power production. The Company expects to continue to purchase capacity in the future from various sources. (See Fuel Supply and Purchased Power and Note 1: to Financial Statements.)

Firm peak load increases over the next ten years are expected to average approximately 2.0% annually, after giving effect to an aggressive load m gement program (including interruptible contracts). The Company's ten year resource plan provides for meeting the increases in required net capability through the completion of nuclear, lignite and gas/oil-fueled combustion turbine capacity additions, through purchased power capacity (including cogeneration and small power production) and through the Company's load management programs. The ten year resource plan is subject to annual review as part of a regular planning process. When compared to the previous ten year resource plan, the current plan reflects a reevaluation of growth expectations which has resulted in the deferral of in-service dates of the Company's Forest Grove lignite unit (Forest Grove nd a coal unit to a date beyond the ten year planning horizon. The components of the ten year resource pian (see Item 2, Properties — Construction Program) are as follows:

	Resource Plan 1992-2001	
Resource Additions	Capability (MW)	Percent
Combustion Turbines	1,580	25%
Lignite	1,500	24
Load Management	1,218	20
Nuclear	1,150	18
Purchas: Power	800	13
Total	6,248	100%

FUEL SUPPLY AND PURCHASED POWER

Net input for 1991 was 87,354 million kilowatt-hours (kWh) of which 76,327 million kWh were generated by the Company. During this period, 836,21[illegible],[illegible]01 million British thermal units (Btu) of fuel (including 40,555,430 million Btu furnished by Aluminum Company of America (Alcoa) at no cost) were consumed for electric generation.

Average fuel and purchased power cost (excluding capacity charges) per kWh of net input was 1.82 cents for 1991, 1.83 cents for 1990 and 1.96 cents for 1989. A comparison of the resource mix for net kWh input and the unit cost per million Btu of fuel to the Company during the last three years is as follows:

	Mix for Net kWh Input			Unit Cost Per Million Btu		
Fuel for Electric Generation:	1991	1990	1989	1991	1990	1989
Gas	37.3%	37.7%	39.4%	$2.47	$2.48	$2.53
Oil	0.1	0.2	1.7	6.07	5.30	4.37
Lignite (a)	43.9	44.4	44.5	1.05	0.96	0.92
Nuclear	6.1	3.9	--	0.33	0.64(b)	—
Total/Weighted Average Fuel Cost	87.4	86.2	85.6	$1.62	$1.63	$1.74
Purchased Power	12.6	13.8	14.4			
Total	100.0%	100.0%	100.0%			

(a) Lignite cost per ton to the Company was $13.48 for 1991, $12.38 for 1990 and $12.07 for 1989.

(b) Unit cost per million Btu in 1990 includes avoided cost of fuel during trial operations. The 1990 cost subsequent to commercial operation was $0.38 per million Btu.

Gas

Fuel gas for units at nineteen of the principal generating stations of the Company, having an aggregate net gas/oil capability of 12,933 MW, was provided during 1991 by Fuel Company. Fuel Company supplied approximately 43% of such fuel gas requirements under contracts with producers at the wellhead and under other contracts with dedicated reserves and 57% under contracts with commercial suppliers. Additional gas/oil-fueled combustion turbines, with an aggregate net capability of 1,580 MW, are planned for the future (see Item 2, Properties — Construction Program).

Fuel Company has acquired under contracts expiring at intervals through 2008, with producers at the wellhead, supplies of gas which are generally expected to be produced over a ten to fifteen year period. As gas production declines and/or contracts expire, new contracts are expected to be negotiated to replenish or augment such supplies. During 1991, no curtailments were experienced under these contracts.

Fuel Company has negotiated gas purchase contracts, ranging in term from one to twenty years, with a number of commercial suppliers. Additionally, Fuel Company has entered into a number of short-term gas purchase contracts with other commercial suppliers at spot market prices; however, these contracts typically do not provide for a firm supply obligation from the seller nor a firm purchase obligation from Fuel Company. During periods of winter peak gas demand, curtailments of gas deliveries have been experienced; however, such curtailments have been of relatively short duration, have had minimal impact on operations and have generally required utilization of fuel oil and gas storage inventories to replace the gas curtailed.

FUEL SUPPLY AND PURCHASED POWER — (Continued)

Gas — (concluded)

Fuel Company owns and operates an intrastate natural gas pipeline system which extends from the gas-producing area of the Permian Basin in West Texas to the East Texas gas fields and southward to the Gulf Coast area. This system includes a one-half interest in a 36-inch pipeline which extends 395 miles from the Permian Basin area of West Texas to a point of termination south of the Dallas-Fort Worth area and has a total estimated capacity of 800 million cubic feet per day with existing compression facilities. Additionally, Fuel Company owns a 39% undivided interest in another 36-inch pipeline, connecting to this pipeline and extending 58 miles eastward to one of Fuel Company's underground gas storage facilities. Fuel Company also owns and operates approximately 1,600 miles of various smaller capacity lines which are used to gather and transport natural gas from other gas-producing areas. The pipeline facilities of Fuel Company form an integrated network through which fuel gas is gathered and transported to certain generating stations of the Company for use in the generation of electric energy.

Fuel Company also owns and operates three underground gas storage facilities with a usable capacity of 27.2 billion cubic feet with approximately 20.7 billion cubic feet of gas in inventory at December 31, 1991. Gas stored in these facilities can currently be withdrawn for use during periods of peak demand, to meet seasonal and other fluctuations or curtailment of deliveries by gas suppliers. Under normal operating conditions, up to 500 million cubic feet can be withdrawn each day for a two week period, with withdrawals at lower rates thereafter.

Oil

During 1991, the Company's utilization of fuel oil as an alternate source of boiler fuel amounted to 107,220 barrels or 0.1% of total fuel requirements. Fuel oil is stored at all nineteen of the principally gas-fueled generating stations. At December 31, 1991, the System Companies had fuel oil storage capacity sufficient to accommodate approximately 6.6 million barrels of oil, with approximately 2.4 million barrels of oil in inventory. Fuel Company has access to an oil pipeline and owns a terminal facility to provide for more dependable and efficient movement of oil. Generally, oil required to replenish that removed from storage will be obtained through purchases in the open market.

Lignite

Lignite is used as the primary fuel in two units in service at the Big Brown generating station (Big Brown), three units at the Monticello generating station (Monticello), three units at the Martin Lake generating station (Martin Lake) and one unit at the Sandow generating station (Sandow), having an aggregate net capability of 5,845 MW (see Item 2, Properties). Two other lignite-fueled units, with an aggregate net capability of 1,500 MW, are included in the current ten year resource plan (see Peak Load and Capability and Item 2, Properties — Construction Program). The Company's lignite units, which are or will be base loaded to operate at the maximum practical capacity factor, have been or will be constructed adjacent to surface mined lignite reserves. At the present time, the Company owns in fee or has under lease an estimated 933 million tons of proven reserves dedicated to existing power plants, plants under construction or plants in the advanced stages of design. Mining Company owns, leases and operates equipment to remove the overburden and to recover lignite. One of the Company's lignite units, Sandow 4, is fueled from lignite deposits owned by Alcoa, which furnishes fuel at no cost to the Company for that portion of energy generated from such unit and dedicated to Alcoa (see Item 6, Selected Financial Data — Operating Statistics). For information concerning applicable air quality standards, see Environmental Matters.

FUEL SUPPLY AND PURCHASED POWER — (Continued)

Lignite — (concluded)

Lignite production operations at Big Brown, Monticello and Martin Lake are accompanied by an extensive reclamation program which returns the land to productive uses and includes a vegetation restoration program. Similar programs are planned for future lignite-fueled generating stations. For information concerning federal and state laws with respect to surface mining, see Environmental Matters.

Coal

The Company continues to evaluate the use of pulverized western coal to supplement its existing lignite fuel supply. The Company has delayed the in-service date of its 650 MW coal unit beyond its ten year resource plan. (See Peak Load and Capability).

Nuclear

The Company is operating one 1,150 MW nuclear-fueled generating unit at the Comanche Peak nuclear generating station (Comanche Peak). A second unit is being constructed at Comanche Peak and is designed for a net capability of 1,150 MW. (See Peak Load and Capability, Comanche Peak Nuclear Generating Station and Item 2, Properties — Construction Program.) Enriched uranium has been purchased for Unit 1 through 1994 and the first three years of operation for Unit 2. Commitments have been obtained for fuel fabrication services for Unit 1 through 1999 and Unit 2 for the first seven years of operation. Uranium hexafluoride conversion services have been contracted for through 2003; and a uranium enrichment contract having a duration of approximately 23 years has been made with the U. S. Department of Energy. Commitments have been obtained for uranium ore concentrates for both units for the period 1993 through 1998. Additional contracts for uranium ore concentrates and nuclear fuel cycle services will be required in the future; however, it is not possible to predict the ultimate availability or cost thereof.

The Nuclear Waste Policy Act of 1982, as amended (NWPA), provides for the development by the federal government of interim storage and permanent disposal facilities for spent nuclear fuel and/or high level radioactive waste materials. The Company is unable to predict when the federal government will be able to provide such storage and disposal facilities. Under provisions of the NWPA, funding for the program will be provided by a one-mill per kWh fee currently levied on electricity generated and sold from nuclear reactors, including the Comanche Peak units. There will be onsite storage capacity for spent fuel sufficient to accommodate the operation of Comanche Peak for approximately 20 years and this storage capacity can be increased, subject to approval by the Nuclear Regulatory Commission (NRC).

Purchased Power

In 1991, the Company purchased 11,027 million kWh or approximately 13% of its energy requirements and had available 1,921 MW of firm purchased capacity or approximately 9% of net capability under contract at the time of peak load. The Company may acquire purchased power capacity in the future to accommodate a portion of its system load and continues to investigate potential available sources. For information concerning the Company ten year resource plan, see Peak Load and Capability.

FUEL SUPPLY AND PURCHASED POWER — (Concluded)

General

The Company is not able to predict: (i) whether or not problems may be encountered in the future in obtaining the fuel and purchased power it will require, (ii) the effect upon its operations of any difficulty it may experience in protecting its rights to fuel and purchased power now under contract, or (iii) the cost of fuel and purchased power. All reasonable costs of fuel and purchased power are generally recoverable subject to the rules of the Public Utility Commission of Texas (PUC). (See Regulation and Rates for information pertaining to the method of recovery of purchased power and fuel costs.)

REGULATION AND RATES

Regulation

Texas Utilities and its subsidiaries, including the Company, are exempt from the provisions of the Public Utility Holding Company Act of 1935, except Section 9(a)(2) which relates to the acquisition of securities of public utility companies.

The Company does not transmit electric energy in interstate commerce or sell electric energy at wholesale in interstate commerce, or own or operate facilities therefor, and its facilities are not connected directly or indirectly to other systems which are involved in such interstate activities, except during the continuance of emergencies permitting temporary or permanent connections or under order of the Federal Energy Regulatory Commission (FERC) exempting the Company from jurisdiction under the Federal Power Act. In view thereof, the Company believes that it is not a public utility as defined in the Federal Power Act and has been advised by its counsel that it is not subject to general regulation under such Act.

The FERC has taken action and Congress is considering proposals designed to increase competition. These developments are designed to promote competition in the generation segment of the industry and increase access to electric transmission systems. Changes to the Public Utility Holding Company Act of 1935 have also been proposed. The Company is unable to predict the ultimate outcome of these developments or what impact, if any, they may have on its operations.

The PUC has original jurisdiction over electric rates and service in unincorporated areas and those municipalities that have ceded original jurisdiction to the PUC and has exclusive appellate jurisdiction to review the rate and service orders and ordinances of municipalities. Generally, the Texas Public Utility Regulatory Act prohibits the collection of any rates or charges (including charges for fuel) by a public utility that do not have the prior approval of the PUC (see Rates). The provisions for inclusion of construction work in progress (CWIP) in rate base provide that such inclusion is an exceptional form of rate relief to be granted only when necessary to the financial integrity of the utility and that it shall not be included for major projects to the extent they have been inefficiently or imprudently planned or managed.

REGULATION AND RATES — (Continued)

Regulation — (concluded)

The construction of new production facilities of the Company is subject to PUC certification. In January 1992, the PUC approved the Notice of Intent (NOI) applications which were filed by the Company in June 1991 for 1,512 MW of combustion turbines and 650 MW of coal-fired generation. An NOI is the first step of a process for PUC approval for construction of utility plant. (See Peak Load and Capability and Item 2, Properties — Construction Programs.)

The System Companies are also subject to various other federal, state and local regulations. (See Comanche Peak Nuclear Generating Station and Environmental Matters.)

Rates

Pursuant to a PUC rule, the recovery of fuel costs is provided through fixed fuel factors. The rule requires refunds of material over-recoveries of fuel cost revenues and reductions in the fixed fuel factors in the event that the utility is materially over-recovered and projects that it will materially over-recover its known or reasonably predictable fuel costs. Material, as defined in the rule, is the lesser of $40 million or 4% of the annual known or reasonably predictable fuel costs most recently approved by the PUC. Final reconciliation of fuel costs is to be made in a utility's general rate case or at a reconciliation proceeding. The rule also provides for an emergency request to increase the fixed fuel factors, which must be acted upon within thirty days on an interim basis by the PUC, if reasonably unforeseeable circumstances have resulted in a material under-recovery of known or reasonably predictable fuel costs. Reconciliation of fuel costs takes place in a general rate case and may be requested otherwise if it has either been over one year since the utility's last fuel reconciliation or the utility has materially under-recovered its known or reasonably predictable fuel costs. In such reconciliation, the utility has the burden of proving that it has generated electricity efficiently, maintained effective cost controls, its non-affiliated fuel and fuel-related contracts have produced the lowest reasonable cost of fuel to ratepayers, and, for fuels acquired from affiliates, all fuel-related expenses are reasonable and necessary and that the prices charged are no higher than prices charged by the supplying affiliate to other of its affiliates or divisions or to unaffiliated persons or corporations for the same item or class of items. Under-recovery reconciliation will be granted only for that portion of fuel costs increased by conditions or events beyond the utility's control. Interest will be paid or received by the utility on any over- or under-recovery of fuel costs at the utility's composite cost of capital as established by the PUC in the utility's most recent general rate case. The rule imposes penalties of up to 10% in the event that interim refunds, when required, are not timely requested and in the event that an emergency increase is granted when there was no emergency. In addition, the PUC rules contain a provision which generally allows recovery through a Power Cost Recovery Factor, on a monthly basis, of purchased power capacity costs from cogenerators not included in base rates. The portion of purchased power costs for fuel is included in the fixed fuel factor.

In January 1990, the Company made applications to the PUC and to its municipal regulatory authorities for upward adjustments in rates for electric service throughout its service area which would increase operating revenues by approximately $442 million, or 10.2%, based upon the test year ended June 30, 1989. Such request reflected costs associated with the commercial operation of Unit 1 of Comanche Peak. On August 13, 1990, pursuant to rules of the PUC, the Company placed its requested rate increase into effect applicable to energy sales on or after such date.

Item 1. BUSINESS (Continued).

REGULATION AND RATES — (Concluded)

Rates — (concluded)

In August 1991, the PUC issued a final order in the rate case. This order was revised and reissued in September 1991. The order provided for a total revenue increase of approximately $442 million and included $695 million of CWIP in rate base to support the revenue increase. It also included a prudence disallowance of $472 million with respect to certain Comanche Peak costs relating to 87.8% of the Company's ownership interest in both units of Comanche Peak. With respect to the Company's reacquisition of the remaining 12.2% minority owner interest in Comanche Peak, the order included an additional disallowance of $909 million. In addition, the order included refunds aggregating $56 million, including interest, principally with respect to fuel gas costs considered imprudent by the PUC. Such amount is being refunded to customers, with interest, over a two year period that began November 1991. The Company strongly disagrees with the order and in November 1991 filed a petition in the 250th Judicial District Court of Travis County, Texas requesting a reversal and remand of the order. Other parties to the PUC proceeding have also filed appeals with respect to various portions of the order. The Company is unable to predict the outcome of these appeals. (See Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations.)

Pursuant to the PUC rule for recovery of fuel costs, and in connection with the September 1991 order in its rate case, the Company received approval from the PUC to reduce its composite fixed fuel factor by 13.4% from its previous interim fuel factor and reconciled its fuel cost through June 30, 1989. Since the beginning of 1986, the Company has been authorized on ten different occasions to refund approximately $685.7 million of over-recovered fuel revenues, including interest. In each instance, the refund has been implemented in billings soon after authorization.

In August 1990, the Company ceased AFUDC accruals and began depreciation provisions on approximately $1.3 billion of investment in Comanche Peak Unit 1, incurred after the end of the June 30, 1989 test year. Depreciation and rate of return on this investment is not provided for in current electric service rates but will be included in the next rate increase request of the Company. As a result, the Company's earnings and liquidity will continue to be affected until the investment incurred subsequent to the end of the test year is included in rates.

Unit 2 at Comanche Peak is scheduled for operation for the peak season of 1993 and the Company believes it will be necessary to request additional rate relief from its regulatory authorities, the amount and exact timing of which is presently undetermined. Upon commencement of operation of Unit 2, the Company currently expects to cease accrual of AFUDC on the Unit 2 investment that exceeds the $695 million included in rate base ($23 million of AFUDC for the month of December 1991); begin depreciation accruals on the accumulated investment in Unit 2 ($3.479 billion at December 31, 1991) and to incur operation and maintenance expenses on the generating unit; all of which are not currently included in the Company's present electric service rates.

A request to place additional amounts of Comanche Peak investment in rate base will be subject to a review by the PUC for prudence of costs incurred. In connection with the September 1991 rate order, the PUC essentially reviewed costs incurred through June 1989 on Unit 2 and through fuel load in February 1990 on Unit 1. At December 31, 1991, the Company had approximately $1.8 billion invested in Comanche Peak that had not been reviewed for prudence. The Company cannot predict the outcome of any future prudence review. (See Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations and Note 12 to Financial Statements.)

COMANCHE PEAK NUCLEAR GENERATING STATION

The Company is subject to the jurisdiction of the NRC with respect to nuclear power plants. NRC regulations govern the granting of licenses for the construction and operation of nuclear power plants and subject such plants to continuing review and regulation. In April 1990, the NRC issued a full power operating license for Unit 1. The construction permit for Unit 2 is in effect and has been extended until a "latest date for completion" of August 1, 1992. The Company has filed an application with the NRC to extend this construction permit for a sufficient period of time to allow for completion of the unit and expects to obtain approval for the extension. For information relating to cost and schedule estimates see Item 2, Properties — Construction Program.

In July 1988, NRC proceedings before an Atomic Safety and Licensing Board, which involved an intervenor, were dismissed pursuant to a joint motion for dismissal filed by the Company, the intervenor and the NRC Staff. Under the terms of this motion, a representative of the intervenor was appointed as a member of the Operations Review Committee (ORC) for Comanche Peak. The ORC is required by the Comanche Peak technical specifications and reviews operational and other safety related matters.

At various times in the past, the Company has paid civil penalties to the NRC for violations of NRC regulatory requirements.

ENVIRONMENTAL MATTERS

The System Companies are subject to various federal, state and local regulations dealing with air and water quality and related environmental matters (see Item 2, Properties — Construction Program for scheduled environmental expenditures).

Air

Under the Texas Clean Air Act, the Texas Air Control Board (TACB) has jurisdiction over the permissible level of air contaminant emissions from generating facilities located within the State of Texas. In addition, the new source performance standards of the Environmental Protection Agency (EPA) promulgated under the federal Clean Air Act, which have also been adopted by the TACB, are applicable to such generating units, the construction of which commenced after September 18, 1978. The Company's generating units have been constructed to operate in compliance with current regulations and emission standards promulgated pursuant to these Acts; however, due to variations in the quality of the lignite fuel, operation of certain of the lignite-fueled generating units at reduced loads is required from time to time in order to maintain compliance with these standards. Generating facilities under construction have received state and federal permits and are generally designed to comply with applicable statutes and regulations.

The federal Clean Air Act Amendments of 1990 (Clean Air Act) include provisions which, among other things, place limits on the sulfur dioxide emissions produced by generating units. The Clean Air Act requires that fossil-fueled plants meet new sulfur dioxide emission standards by 1995 (Phase I) and additional sulfur dioxide emission standards by 2000 (Phase II). The Company's generating units are not affected by the Phase I requirements. The Phase II requirements are currently met by all but four of the Company's generating units. Because the sulfur dioxide emissions from these four units are relatively low and alternatives are available to enable these units to reduce sulfur dioxide emissions, compliance with the applicable Phase II sulfur dioxide requirements is not expected to have a significant impact on the Company. The Company has not finalized a compliance plan due to the uncertainty of the requirements which the EPA may include in the regulations.

ENVIRONMENTAL MATTERS — (Continued)

Air — (concluded)

To meet these sulfur dioxide requirements, the Clean Air Act provides for the annual allocation of sulfur dioxide emission allowances to utilities. Utilities will be permitted to transfer allowances within their own systems and to buy or sell allowances in a new allowance trading market to be established under the Clean Air Act. The EPA will grant a maximum number of allowances annually to the Company based on the amount of emissions from units in operation in 1985. The Clean Air Act also provides that the Company will be granted additional annual allowances for certain Company units under construction based on part of their anticipated emissions. The Company intends to utilize internal allocation of emission allowances within its system and, if necessary, to purchase emission allowances to enable both existing and future electric generating units to meet the requirements of the Clean Air Act. The Company is unable to predict the extent to which it may generate excess allowances or will be able to acquire allowances from others if needed.

Other provisions of the Clean Air Act may require the Company to take other actions. The Company's lignite-fired generating units currently meet the required nitrogen oxide limits in the Clean Air Act. The requirements of the Clean Air Act for ozone nonattainment areas may require nitrogen oxide emission reductions at the Company's natural gas-fired units in the Dallas-Fort Worth area by 1996. The Clean Air Act also requires studies over a four year period by the EPA to assess the potential for toxic emissions from utility boilers. The Company is unable to predict whether any reductions in toxic emissions will ultimately be required. Continuous emission monitoring systems are required by the Clean Air Act to be installed by 1995 on all of the Company's fossil-fueled units.

Only certain parts of the regulations implementing the Clean Air Act have been adopted. Until more of these regulations have been promulgated, the Company will not be able to fully determine the cost or method of compliance for these requirements. Similar capital and operating costs associated with new requirements or compliance measures have historically been recovered through rates. The Company expects any such future costs would be recovered through rates as well.

Water

The Texas Water Commission (TWC) and the EPA have jurisdiction over all water discharges (including storm water) from generating stations and mining areas. The Company's generating stations presently in operation have been constructed to operate in compliance with applicable state and federal requirements relating to discharge of pollutants into the water. The Company and Mining Company have obtained all required waste water discharge permits from the TWC and the EPA for facilities in operation and have applied for or obtained all such permits for facilities under construction. The Company and Mining Company believe they can satisfy the requirements necessary to obtain any required permits or renewals.

Diversion, impoundment and withdrawal of water for cooling and other purposes is subject to the jurisdiction of the TWC. The Company possesses all necessary permits for these activities from the TWC for its present operations and plants under construction.

Item 1. BUSINESS (Concluded).

ENVIRONMENTAL MATTERS — (Concluded)

Other

Federal legislation regulating surface mining was enacted in August 1977 and regulations implementing the law have been issued. Mining Company's lignite mining operations are currently regulated at the state level by the Railroad Commission of Texas. Surface mining permits have been issued for current Mining Company operations that provide fuel for Big Brown, Monticello and Martin Lake.

Treatment, storage and disposal of solid and hazardous wast. are regulated at the state level under the Texas Solid Waste Disposal Act and at the federal level under the Resource Conservation and Recovery Act of 1976, as amended (RCRA). The EPA has issued regulations under the RCRA and the TWC has issued regulations under the Texas act applicable to the Company generating units. The Company has registered its disposal sites and has obtained or applied for such permits as are required by such regulations.

Under the federal Low-Level Radioactive Waste Policy Act of 1980, as amended, the State of Texas is required to provide by 1996, either on its own or jointly with other states in a compact, for the disposal of all low-level radioactive waste generated within the state. The State of Texas is taking steps to site, construct and operate a low-level radioactive waste disposal site by 1996. Although the state failed to meet the January 1, 1992 federal deadline for filing a license application for a low-level waste disposal facility, progress is being made toward the filing of the application by mid 1992.

Item 2. PROPERTIES.

At December 31, 1991, the Company owned and operated sixty-nine electric generating units at twenty-four stations having a total net capability of 18,953 MW. The locations of the principal electric generating stations and transmission lines of the Company are indicated on the map included herein. Forty generating units with a net capability of 8,506 MW use natural gas as the primary fuel and are designed to use fuel oil for short periods when the gas supply is interrupted or curtailed; two units with a net capability of 750 MW use natural gas only; five units with a net capability of 2,680 MW use natural gas as the primary fuel and are designed to use fuel oil for extended periods; nine units with a net capability of 5,845 MW use lignite as fuel; twelve units with a net capability of 22 MW are diesel units; and one unit with a net capability of 1,150 MW uses nuclear fuel.

The Company currently leases fifteen combustion turbine generating units. The units are designed to use natural gas or fuel oil and have a total net capability of 975 MW.

The principal generating facilities and load centers of the Company are connected by 3,823 circuit miles of 345,000 volt transmission lines and 9,028 circuit miles of 138,000 and 69,000 volt transmission lines.

The Company is connected by six 345,000 volt lines to Houston Lighting & Power Company; by three 345,000 volt, seven 138,000 volt and nine 69,000 volt lines to West Texas Utilities Company; by two 345,000 volt, seven 138,000 volt and one 69,000 volt lines to Lower Colorado River Authority; by four 345,000 volt and eight 138,000 volt lines to the Texas Municipal Power Agency; and at several points with smaller systems operating wholly within Texas. The Company is a member of the Electric Reliability Council of Texas (ERCOT), an intrastate network of investor-owned entities, cooperatives and public entities. ERCOT is the regional reliability coordinating organization for member electric power systems in Texas.

The generating stations and other important units of property of the Company are located on lands owned primarily in fee simple. The greater portion of the transmission and distribution lines of the Company, and of the gas gathering and transmission lines of Fuel Company, has been constructed over lands of others pursuant to easements or along public highways and streets as permitted by law. The rights of the System Companies in the realty on which their properties are located are considered by them to be adequate for their use in the conduct of their business. Minor defects and irregularities customarily found in titles to properties of like size and character may exist, but any such defects and irregularities do not materially impair the use of the properties affected thereby. The Company and Fuel Company have the right of eminent domain whereby they may, if necessary, perfect or secure titles to privately held land used or to be used in their operations. Electric plant of the Company is generally subject to the liens of its mortgages.

During the period from January 1, 1989, to December 31, 1991, the Company made gross property additions of approximately $3,321,310,000 and retirements of property aggregating approximately $160,792,000. Such gross additions amounted to 17.0% of electric plant at December 31, 1991.

CONSTRUCTION PROGRAM

Construction expenditures, excluding an allowance for funds used during construction (AFUDC) (see Note 1 to Financial Statements), for the years 1992 through 1994 are estimated as follows:

	1992	1993	1994
	Thousands of Dollars		
Electric Property:			
Production			
Comanche Peak Unit 2	$400,000	$ 50,000	$ -
Other Production	71,000	247,000	438,000
Other Production - Environmental (a)	13,000	65,000	87,000
Total Production	$484,000	$362,000	$525,000
Transmission	40,000	41,000	43,000
Distribution	201,000	235,000	241,000
General	15,000	26,000	28,000
Total	$740,000	$664,000	$837,000
Such expenditures do not include amounts for:			
Nuclear Fuel (excluding AFUDC)	$6,000	$10,000	$12,000

(a) The Company is subject to federal, state and local regulations dealing with environmental protection (see Item 1, Business—Environmental Matters). Such expenditures for existing units approximated $10,400,000 for 1991, $15,500,000 for 1990 and $6,400,000 for 1989.

Additional generating units planned for future years are described as follows:

Comanche Peak Nuclear Generating Unit 2

Unit 2 is scheduled for service for the peak season of 1993. At December 31, 1991, the Company had $3.479 billion invested in Unit 2 (net of $485 million included in the reserve for regulatory disallowances required by the PUC order, see Note 12 to Financial Statements), including AFUDC. The estimated cash requirements in 1992 and 1993 to complete Unit 2 are approximately $450 million in the aggregate. No estimate for AFUDC accruals on Unit 2 is provided due to the uncertainty of regulatory treatment and the exact month of commercial operation. Such accruals approximated $23 million for the month of December 1991 for Unit 2.

Other Generating Units

The Company's ten year resource plan includes two lignite-fueled 750 MW units at Twin Oak scheduled for service for the peak season of 1997 and 1998, respectively. Active construction and the accrual of AFUDC on the Twin Oak units was suspended in September 1987 and is expected to resume in 1993. Estimated construction expenditures, excluding AFUDC, for the 1992-1994 period include approximately $431 million applicable to these generating units. The lignite-fueled Forest Grove unit, previously scheduled for service in the peak season of 1999, has been deferred beyond the ten year resource plan period. Construction activities and accrual of AFUDC for Forest Grove Unit 1 were suspended in September 1987.

CONSTRUCTION PROGRAM — (Concluded)

Other Generating Units — (concluded)

The remainder of the Company's ten year resource plan includes 1,580 MW of gas/oil-fueled generating units, none of which require significant construction expenditures in the 1992-1994 period reflected above. (See Item 1, Business — Peak Load and Capability.)

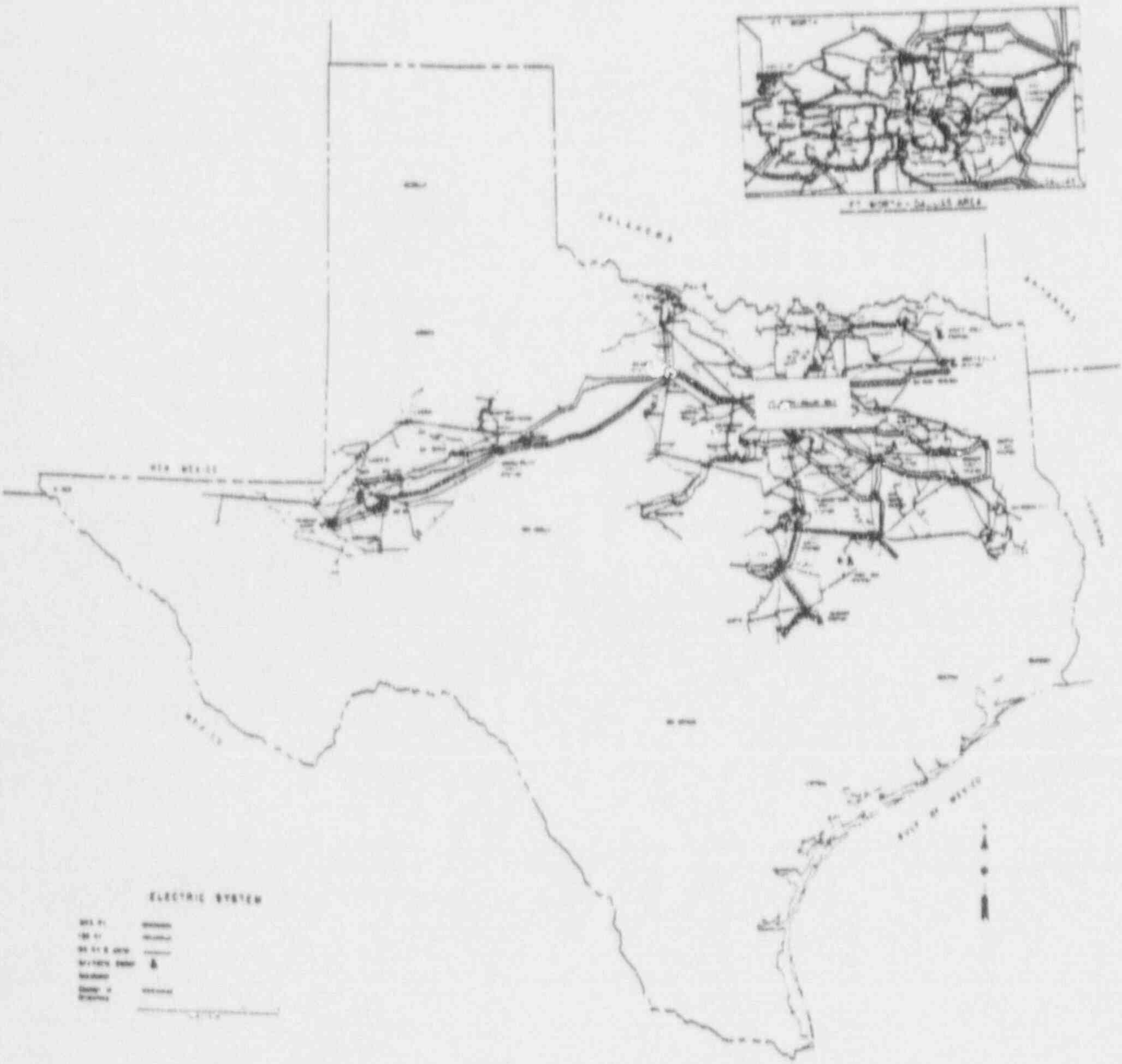
The effects of inflation on construction costs, the reevaluation of growth expectations or additional regulatory requirements may result in changes in estimated completion costs and in-service dates for certain generating units in design or under construction. Actual expenditures and dates of completion may further vary because of other uncertain factors such as licensing delays, changes in peak load requirements and cost and availability of fuel, labor, materials and capital. Commitments in connection with the construction program, principally for generating stations and related facilities, are generally revocable subject to reimbursement to manufacturers for expenditures incurred or other cancellation penalties.

For information regarding financing of the construction program see Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations.

Item 2. PROPERTIES (Concluded).

THE COMPANY SYSTEM

December 31, 1991



Item 3. LEGAL PROCEEDINGS.

On November 21, 1991, Sheree Anne Meyer, as custodian for Adam Joseph Davenport, allegedly as a shareholder of Texas Utilities, filed suit in the United States District Court for the Northern District of Texas derivatively on behalf of Texas Utilities and the Company against Texas Utilities and the Company as nominal defendants and J. S. Farrington, Erle Nye, James K. Dobey, Jack W. Evans, William M. Griffin, Margaret N. Maxey, James A. Middleton, Charles R. Perry and William H. Seay, directors of Texas Utilities, and James H. Zumberge, a former director of Texas Utilities, S. S. Swiger, an officer of Texas Utilities, and T. L. Baker, an officer of the Company. The plaintiff alleges breaches of fiduciary duty and negligence primarily relating to Comanche Peak, which the plaintiff claims have resulted in damages in an amount not less than $1.381 billion. In December 1991, the Court entered an order which stays this suit until thirty days after entry of a final judgment by the District Court in the Company's appeal of the final order of the PUC in its rate case. (See Item 1, Business —— Regulation and Rates.)

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

None.

PART II

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

All of the Company's common stock is owned by Texas Utilities.

Reference is made to Note 6 to Financial Statements regarding limitations upon payment of dividends on common stock of the Company.

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Item 6. SELECTED FINANCIAL DATA.

FINANCIAL STATISTICS

	Year Ended December 31,				
	1991*	1990	1989	1988	1987
TOTAL ASSETS end of year (thousands)	$17,093,474	$17,387,276	$16,173,648	$14,828,250	$12,938,655
ELECTRIC PLANT — GROSS end of year (thousands)	$20,865,047	$19,693,580	$18,116,758	$16,370,676	$14,149,647
Accumulated depreciation and amortization end of year	3,417,856	3,038,302	2,762,101	2,558,282	2,355,827
Reserve for regulatory disallowances end of year	1,308,460	—	—	—	—
Constru[illegible]ion expenditures (including allowance for funds used during construction)	1,195,680	1,431,647	1,793,890	1,542,974	1,662,483
CA[illegible] end of year (thousands)					
L[illegible]	$ 7,253,626	$ 6,750,635	$ 6,079,503	$ 5,872,613	$ 4,639,111
[illegible]					
Not subj[illegible]ory redemption	1,007,728	1,007,728	1,007,732	909,582	909,633
Subj[illegible] redemption	425,758	426,737	329,009	328,770	232,906
[illegible]	5,741,437	6,452,690	5,814,013	5,278,697	4,827,145
[illegible]	$14,428,549	$14,637,790	$13,230,257	$12,389,662	$10,608,795
EM[illegible]REST COST ON LONG-TERM DEBT end of year	9.7%	9.8%	[illegible]	9.9%	9.8%
EMBEDDED DIVIDEND COST ON PREFERRED STOCK end of year	8.5%	8.6%	8.3%	8.3%	8.3%
NET INCOME (LOSS)(thousands)	$(289,173)	$964,276	$886,176	$747,062	$781,178
DIVIDENDS DECLARED ON COMMON STOCK (thousands)	$ 650,940	$607,230	$542,298	$500,968	$447,200
RATIO OF EARNINGS TO FIXED CHARGES	0.3	2.5	2.6	2.6	3.3
ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION AS PERCENT OF EARNINGS TO COMMON STOCK	— %	73.1%	65.1%	59.3%	55.9%
RETURN ON AVERAGE COMMON STOCK EQUITY	(6.7)%	13.8%	14.0%	12.9%	15.2%
CASH FLOWS FROM OPERATIONS (less dividends paid) AS A PERCENT OF CASH CONSTRUCTION EXPENDITURES	27.1%	24.0%	12.6%	10.7%	20.6%

* Certain financial statistics for the year 1991 were affected by the Company's recording a charge against earnings, representing provisions for disallowances in the rate order issued by the Public Utility Commission of Texas. (See Note 12 to Financial Statements.)

Item 6. **SELECTED FINANCIAL DATA (Concluded).**

OPERATING STATISTICS

	Year Ended December 31,				
	1991	1990	1989	1988	1987
ELECTRIC ENERGY GENERATED AND PURCHASED (MWh)					
Generated — net station output	76,326,601	76,044,403	74,925,395	73,493,397	71,878,925
Purchased and net interchange	11,027,061	12,179,724	12,588,899	12,095,385	11,019,037
Total generated and purchased	87,353,662	88,224,127	87,514,294	85,588,782	82,897,962
Company use, losses and unaccounted for	4,996,123	4,496,294	5,571,768	4,864,236	5,125,310
Total electric energy sales	82,357,539	83,727,833	81,942,526	80,724,546	77,772,652
ELECTRIC ENERGY SALES (MWh)					
Residential	28,505,885	28,157,802	27,294,613	26,722,342	25,801,012
Commercial	23,012,114	23,429,101	22,539,351	21,899,895	21,084,673
Industrial	21,482,750	21,839,196	21,377,542	21,516,862	20,678,324
Government and municipal	5,056,868	4,914,503	4,683,259	4,583,505	4,397,085
Total general business	78,057,617	78,340,602	75,894,765	74,722,604	71,961,094
Other electric utilities	4,299,922	5,387,231	6,047,761	6,001,942	5,811,558
Total electric energy sales	82,357,539	83,727,833	81,942,526	80,724,546	77,772,652
OPERATING REVENUES (thousands)					
Residential	$2,043,421	$1,859,239	$1,752,679	$1,704,219	$1,609,491
Commercial	1,391,995	1,266,030	1,228,672	1,182,869	1,105,179
Industrial	852,953	801,821	817,802	815,887	766,657
Government and municipal	303,597	273,596	251,941	245,249	229,877
Total general business	4,591,965	4,200,686	4,051,094	3,948,224	3,711,204
Other electric utilities	228,075	232,755	245,821	239,937	221,413
Total from electric energy sales	4,820,040	4,433,441	4,296,915	4,188,161	3,932,617
Other operating revenues (including over/under-recovered fuel revenue)	71,482	107,474	21,650	(36,343)	146,684
Total operating revenues	$4,891,522	$4,540,915	$4,318,565	$4,151,818	$4,079,301
ELECTRIC CUSTOMERS (end of year)					
Residential	1,921,119	1,900,005	1,875,524	1,858,727	1,844,024
Commercial	205,555	205,359	210,824	209,520	208,727
Industrial	22,156	22,214	22,024	22,179	22,398
Government and municipal	27,719	24,538	23,434	20,037	19,655
Total general business	2,176,549	2,152,116	2,131,806	2,110,463	2,094,804
Other electric utilities	247	63	64	64	62
Total electric customers	2,176,796	2,152,179	2,131,870	2,110,527	2,094,866
RESIDENTIAL STATISTICS (excludes master-metered customers, MWh sales and revenues)					
Average kWh per customer	14,099	14,050	13,754	13,505	13,153
Average revenue per kWh	7.26¢	6.69¢	6.50¢	6.48¢	6.33¢

Industrial classification includes service to Alcoa-Sandow:	1991	1990	1989	1988	1987
Electric energy sales (MWh)	3,359,824	3,517,431	3,276,203	3,525,416	3,409,332
Operating revenues (thousands)	$55,987	$55,274	$56,985	$56,608	$62,630

In 1991, a change was made in the method of counting other electric utility customers and prior periods have been changed to reflect a reclassification made in 1991 of certain customers among various classes, principally from commercial to government and municipal.

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

Liquidity and Capital Resources

The primary capital requirements of Texas Utilities Electric Company (Company) in 1991 and as estimated for 1992 through 1994 are as follows:

	1991	1992	1993	1994
		Thousands of Dollars		
Cash construction expenditures (excluding allowance for funds used during construction)	$ 864,000	$ 740,000	$664,000	$ 837,000
Nuclear fuel (excluding allowance for funds used during construction)	4,000	6,000	10,000	12,000
Maturities and redemptions of long-term debt, sinking fund requirements and redemptions of preferred stock	237,000	540,000	175,000	157,000
Total	$1,105,000	$1,286,000	$849,000	$1,006,000

For detail concerning major construction work now in progress or contemplated by the Company and the commitments with respect thereto, see Item 2, Properties -- Construction Program and Note 13 to Financial Statements.

The Company has generated cash from operations sufficient to meet operating needs, pay dividends on capital stock and finance a portion of capital requirements. Factors affecting the ability of the Company to continue to fund a portion of its capital requirements from operations include adequate rate relief in the future reflecting regulatory practices allowing recovery of capital investment through adequate depreciation rates, normalization of federal income taxes, recovery of the cost of fuel and purchased power and the opportunity to earn competitive rates of return required in the capital markets. For 1991, approximately 27% of the cash needed for construction expenditures was generated from operations by the Company.

In August 1990, the Company placed Comanche Peak Unit 1 in commercial operation and implemented its requested rate increase under bond, based on a test year ended June 30, 1989. In a September 1991 order, the Public Utility Commission of Texas (PUC) substantively approved the level of rates implemented under bond and, pursuant to this order, which the Company has appealed in state district court, the Company recorded the provision for regulatory disallowances of certain costs associated with Comanche Peak in the amount of $1.381 billion ($1.011 billion after tax). In addition, the Company recorded a charge of $56 million, including interest ($37 million after tax), representing principally fuel gas costs disallowed by the order. (For additional information regarding the rate decision, see Results of Operations and Note 12 to Financial Statements.) As a result, the Company will be precluded for a period of approximately twelve months from the date of recording such disallowances from incurring certain forms of debt and issuing preferred stock. The Company has taken a number of steps to reduce expenses, including a hiring freeze, and continues to review methods to permanently reduce its operating and capital expenditures. The approved rates have improved cash flows from operations and will reduce future financing requirements. Because of the Company's current cash and cash investments, credit lines, sales of common stock and cash from operations, the Company does not anticipate a significant change in its ability to fund continuing operations and its capital requirements.

Item 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS (Continued).

Liquidity and Capital Resources — (continued)

In August 1990, the Company ceased allowance for funds used during construction (AFUDC) accruals and began depreciation provisions on approximately $1.3 billion of investment in Comanche Peak Unit 1, incurred after the end of the June 30, 1989 test year. Depreciation and rate of return on this investment is not provided for in current electric service rates but will be included in the next rate increase request of the Company. As a result, the Company's earnings and liquidity will continue to be affected until the investment incurred subsequent to the end of the test year is included in rates. See Item 1, Business — Regulation and Rates and Note 12 to Financial Statements regarding the Company's need for future rate increases.

Although the Company cannot predict the outcome of its appeal of the recent rate decision, future regulatory action or any changes in economic and securities market conditions, no changes are expected in trends or commitments which might significantly alter its basic financial position.

External funds of a permanent or long-term nature are obtained through the sales of common stock to Texas Utilities Company (Texas Utilities), preferred stock and long-term debt, subject to the current limitations previously discussed. The capitalization ratios of the Company at December 31, 1991, consisted of approximately 50% long-term debt, 10% preferred stock and 40% common stock equity. These ratios were primarily affected in 1991 by the recording of the Comanche Peak disallowances and the financing activities described below. The Company expects these ratios to return to their previous levels over time, assuming adequate rate relief and recovery of capital investment.

Financings in 1991 by the Company included the following:

Long-Term Debt:

Month	Principal Amount	Description
January	$ 17,000,000	Secured Medium-Term Notes - Series C
February	40,000,000	Secured Medium-Term Notes - Series C
March	100,000,000	7-7/8% Collateralized Pollution Control Revenue Bonds due 2021
May	300,000,000	9-3/4% First Mortgage and Collateral Trust Bonds due 2021
July	75,000,000	Collateralized Pollution Control Revenue Bonds - Taxable Series 1991A due 2021
July	50,000,000	Collateralized Pollution Control Revenue Bonds - Taxable Series 1991B due 2021
July	50,000,000	Collateralized Pollution Control Revenue Bonds - Taxable Series 1991C due 2021
July	100,000,000	Collateralized Pollution Control Revenue Bonds - Taxable Series 1991D due 2021
Total	$732,000,000	

Common Stock:

Month	Shares	Net Proceeds	Description
June	3,125,000	$150,000,000	Without par value
December	3,950,000	200,463,000	Without par value
		$350,463,000	

In 1991, the Company redeemed or made principal payments aggregating $237,178,000 on preferred stock and long-term debt. Early redemptions of long-term debt and preferred stock may occur from time to time in amounts presently undetermined. For information regarding short-term financings of the Company, see Note 3 to Financial Statements.

Liquidity and Capital Resources — (concluded)

Although the Company is currently restricted from issuing certain forms of debt, the Company is able to replace existing debt under its mortgages. In February 1992, the Company sold $150,000,000 of its First Mortgage and Collateral Trust Bonds, 8-1/8% series due February 1, 2002 and $175,000,000 of its First Mortgage and Collateral Trust Bonds, 8-7/8% series due February 1, 2022. The funds acquired from these sales and funds from operations were used to redeem the following series of the Company's First Mortgage and Collateral Trust Bonds: $100,000,000 of its 12% series due August 1, 2015; $75,000,000 of its 12% series due September 1, 2015; and $150,000,000 of its 11-1/8% series due December 1, 2015. Also in February 1992, the Company announced plans to redeem $50,000,000 of its Texas Power & Light Company First Mortgage Bonds, 10-1/8% series due October 1, 2004 and $75,000,000 of its Texas Electric Service Company First Mortgage Bonds, 11-5/8% series due December 1, 2012.

Sales of additional equity securities may occur from time to time, in amounts and of types presently undetermined, subject to the preferred stock limitations previously discussed.

In November 1990, the federal Clean Air Act Amendments of 1990 (Clean Air Act) were enacted which, among other things, place limits on the sulfur dioxide emissions produced by generating units. The Clean Air Act requires that fossil-fueled plants meet new sulfur dioxide emission standards by 1995 (Phase I) and additional sulphur dioxide emission standards by 2000 (Phase II). The Company's generating units are not affected by Phase I requirements. The Phase II requirements are currently met by all but four of the Company's generating units. Other provisions of the Clean Air Act may require the Company to take other actions; however, only certain parts of the regulations implementing requirements have been adopted. Until these regulations have been promulgated, the Company will not be able to fully determine the cost or method of compliance for these requirements.

The above capital requirements have not been significantly affected by the Clean Air Act's requirements. Although the Company is unable to fully determine the cost to comply with the Clean Air Act, it is not expected to have a significant impact on the Company. Any additional capital costs, as well as any increased operating costs associated with these new requirements, are expected to be recovered through rates, as similar costs have been recovered in the past. (See Item 1, Business — Environmental Matters, and Note 13 to Financial Statements.)

See Item 6, Selected Financial Data — Financial Statistics for additional information.

Item 7. **MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS (Continued).**

Results of Operations

Operating revenues increased 7.7% and 5.1% for the years ended December 31, 1991 and 1990, respectively. The following table details the factors contributing to these changes:

Factors	Increase (Decrease) 1991	1990
	Thousands of Dollars	
Base rate revenue	$ 548,973	$ 367,249
Fuel revenue	(73,827)	(107,197)
Power cost recovery factor revenue	(129,073)	(26,426)
Other	4,534	(11,276)
Total	$ 350,607	$ 222,350

Base rate revenue in both periods was affected by higher rate levels in 1991 and a portion of 1990. Energy sales decreased 1.6% for 1991 and increased 2.2% for 1990. The decrease in 1991 is due to decreased customer usage resulting from the effects of economic conditions and milder weather, partially offset by increased customers. The increase in 1990 was primarily due to increased customers and customer usage. The rate increase placed in effect in August 1990 increased base rate revenue approximately $583,000,000 for 1991 and $294,000,000 for 1990, including approximately $132,000,000 for 1991 and $67,000,000 for 1990 reclassified from power cost recovery factor revenue to base rate revenue. Fuel revenues have decreased, reflecting a lower fuel factor in connection with the new rates, and in 1991 included a reduction of approximately $29,000,000, principally due to the PUC's order to refund disallowed fuel gas purchases incurred during the period from April 1983 to June 1989. (See Note 12 to Financial Statements.)

Fuel and purchased power expense decreased 1.3% and 3.1% for 1991 and 1990, respectively. The decrease for both periods was due to a lower cost of nuclear fuel and gas and in 1991 to a reduction in off-system power purchases. The decrease in 1991 was partially offset by a higher unit cost for fuel oil and lignite. (See Item 1, Business — Fuel Supply and Purchased Power and Item 6, Selected Financial Data — Operating Statistics.)

Total operating expenses, excluding fuel and purchased power, increased 18.7% and 16.0% for 1991 and 1990, respectively. Operation, maintenance and depreciation expenses increased in both years primarily due to the commercial operation of Comanche Peak Unit 1. Amortization of rate case related expenses and increased employee related costs also contributed to the 1991 increase in operation expense. The increase in operation expense in 1990 was due to increased combustion turbine lease expense and costs associated with the sales of customer accounts receivable. Maintenance expense for 1990 also increased due to the timing of certain plant overhauls and increased maintenance on distribution equipment. Taxes other than income increased in 1991 due primarily to increased property taxes, franchise taxes and increased state and local gross receipts taxes. In 1991, property taxes reflect the effects of legislation passed creating county education districts. This legislation was declared unconstitutional by the Texas Supreme Court on January 30, 1992 and the court has instructed the State legislature to provide a revised plan for school funding by June 1, 1993 with the current plan to remain in effect pending action by the legislature. Taxes other than income increased in 1990 primarily due to the effect of a franchise tax refund recorded in the prior year.

Item 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS (Continued).

Results of Operations — (concluded)

AFUDC decreased 41.1% in 1991 and increased 22.1% in 1990. The decrease in 1991 was due primarily to the full year's effect of the discontinuation of the accrual of AFUDC on Comanche Peak Unit 1 when the unit was placed in commercial operation in August 1990 and the effect of the implementation of the rate order in October 1991 by placing $695 million of construction work in progress (CWIP) in rate base and the exclusion of $485 million of CWIP disallowed on Unit 2 of Comanche Peak. The decrease was partially offset by the effect of the increase in AFUDC rates in 1991. (See Note 1 to Financial Statements.) The increase in 1990 was primarily due to the resumption of the accrual of AFUDC on Comanche Peak Unit 2 and the Company's continuing construction at Comanche Peak. The increase was partially offset by the discontinuation of the accrual of AFUDC on Comanche Peak Unit 1 when the unit was placed in commercial operation in August 1990.

The provision for regulatory disallowances reflects a charge to comply with the PUC's decision in the Company's rate case. The decision, which the Company is appealing, included a prudence disallowance of $472 million with respect to certain Comanche Peak costs relating to 87.8% of the Company's ownership interest in both units of Comanche Peak. In addition, the decision provided for a disallowance of $909 million for costs associated with the Company's reacquisition of the remaining 12.2% minority owner interest in Comanche Peak. (See Note 12 to Financial Statements.)

Other income and deductions — net increased for 1991 primarily due to increased interest income.

Federal income taxes — other income decreased in 1991 due to the effect of recording the taxes associated with the provision for regulatory disallowances. (See Notes 8 and 12 to Financial Statements.)

Total interest charges, excluding AFUDC, increased 6.0% and 11.9% in 1991 and 1990, respectively. Interest on mortgage bonds increased due to new issues sold during current periods and annualized interest on issues sold in prior periods, partially offset by retirements and redemptions of certain higher interest rate issues. Interest on other long-term debt decreased in 1991 due to the continuing retirement of debt incurred on the purchases of the minority ownership interests in Comanche Peak. Other interest expense increased in 1991 due to interest associated with the PUC's order to refund disallowed fuel gas costs and interest associated with the settlement of prior years' federal income tax returns.

The net loss in 1991 was due to the recognition of the provision for regulatory disallowances and the provision for refunds and related interest described above and in Note 12 to Financial Statements. Another major factor affecting earnings was the discontinuation of the accrual of AFUDC on approximately $1.3 billion of investment in Comanche Peak Unit 1, incurred after the end of the test year, which is not provided for in new rates but which will be included in future rate increase requests. Net income increased in 1990 primarily due to the resumption of the accrual of AFUDC on Unit 2 of Comanche Peak.

Preferred stock dividends increased 2.8% and 8.8% in 1991 and 1990, respectively, due to the full periods' effect of prior period issuances. Also in 1990, the increase was affected by new issues sold.

Item 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS (Concluded).

Pending Accounting Changes

In December 1990, the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standards No. 106, "Employers' Accounting for Postretirement Benefits Other Than Pensions", which is effective for fiscal years beginning after December 15, 1992. The Statement requires a change in the accounting for a company's obligation to provide health care and certain other benefits to its retirees from the "pay-as-you-go" method to an accrual method and requires the cost of the obligation to be recognized in the period from employment date until full eligibility for benefits. The Company currently estimates that the unfunded actuarial present value of employee service rendered to the expected date of adoption (transition obligation at January 1, 1993), to be approximately $210 million to $260 million. The Statement allows the transition obligation to be either recognized immediately as the cumulative effect of a change in accounting principle or amortized evenly over the longer of the average remaining service lives of covered employees or 20 years. The Company expects to recognize the transition obligation over the average remaining service lives of covered employees. The total annual benefits cost is estimated to be approximately $35 million to $50 million. The Company expects that the accrual of benefits cost will either be recovered currently through rates, similar to retirement plan costs, or, pursuant to certain provisions of the Statement, that a regulatory asset will be recorded to reflect amounts, if any, whose future recovery is probable through rates as costs are paid. Therefore, this Statement is not expected to have a material effect on the Company's financial position or results of operations.

In February 1992, the FASB issued Statement of Financial Accounting Standards No. 109, "Accounting for Income Taxes", which is effective for fiscal years beginning after December 15, 1992. The Statement, among other things, requires the liability method of recognition for all temporary differences, requires that deferred tax liabilities and assets be adjusted for an enacted change in tax laws or rates and prohibits net-of-tax accounting and reporting. Certain provisions of the Statement provide that regulated enterprises are permitted to recognize such adjustments as regulatory assets or liabilities if it is probable that such amounts will be recovered from or returned to customers in future rates. Although application of the Statement will increase both total assets and liabilities, these requirements are not expected to have a material effect on the Company's financial position or results of operations.

Effective January 1992, the Company began recording base rate revenue for energy sold but not billed to achieve a better matching of revenues and expenses. The cumulative effect of the change for prior periods will increase 1992 earnings after income taxes by approximately $80 million.

Item 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA.

TEXAS UTILITIES ELECTRIC COMPANY

STATEMENTS OF INCOME

	Year Ended December 31,		
	1991	1990	1989
		Thousands of Dollars	
OPERATING REVENUES	$4,891,522	$4,540,915	$4,318,565
OPERATING EXPENSES			
Fuel and purchased power	1,756,423	1,779,854	1,837,025
Operation	729,615	645,857	541,652
Maintenance	304,683	289,949	259,693
Depreciation and amortization	425,216	316,527	240,466
Federal income taxes	152,963	136,060	146,589
Taxes other than income	437,347	338,323	299,588
Total operating expenses	3,806,247	3,506,570	3,325,013
OPERATING INCOME	1,085,275	1,034,345	993,552
OTHER INCOME (LOSS)			
Allowance for equity funds used during construction	251,744	402,447	331,365
Provision for regulatory disallowances (Note 12)	(1,381,145)	—	—
Other income and deductions — net	12,462	4,687	6,612
Federal income taxes (Notes 8 and 12)	362,852	(1,435)	(2,209)
Total other income (loss)	(754,087)	405,699	335,768
TOTAL INCOME	331,188	1,440,044	1,329,320
INTEREST CHARGES			
Interest on mortgage bonds	608,729	551,986	518,290
Interest on other long-term debt	61,822	92,749	59,278
Other interest	62,111	46,604	40,400
Allowance for borrowed funds used during construction	(112,301)	(215,571)	(174,824)
Total interest charges	620,361	475,768	443,144
NET INCOME (LOSS)	(289,173)	964,276	886,176
PREFERRED STOCK DIVIDENDS	121,603	118,268	108,712
NET INCOME (LOSS) AFTER PREFERRED STOCK DIVIDENDS	$ (410,776)	$ [illegible]46,008	$ 777,464

See accompanying Notes to Financial Statements.

TEXAS UTILITIES ELECTRIC COMPANY

STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	1991	1990	1989
		Thousands of Dollars	
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income (loss)	$ (289,173)	$ 964,276	$ 886,176
Adjustments to reconcile net income (loss) to cash provided by operating activities:			
Depreciation	418,899	314,044	240,466
Deferred federal income taxes — net	(247,264)	27,464	14,429
Federal investment tax credits — net	(53,498)	33,841	26,090
Allowance for equity funds used during construction	(251,744)	(402,447)	(331,365)
Amortization of regulatory assets	17,540	11,087	—
Amortization of nuclear fuel	14,086	8,016	—
Provision for regulatory disallowances (Note 12)	1,381,145	—	—
Provision for refunds and related interest — net (Note 12)	44,893	—	—
Cash flows from operations	1,034,884	956,281	835,796
Changes in assets and liabilities:			
Receivables — net	(29,854)	59,820	125,764
Inventories	(19,224)	(45,215)	16,729
Accounts payable — net	(17,095)	(39,429)	46,256
Interest and taxes accrued	84,021	16,608	5,052
Other working capital	42,999	(13,882)	653
Over/under-recovered fuel revenue	(43,529)	(53,704)	32,568
Deferred taxes on over/under-recovered fuel revenue	14,800	18,259	(11,082)
Other — net	21,105	45,044	(5,470)
Net cash flows from operating activities	1,088,107	943,782	1,046,266
CASH FLOWS FROM FINANCING ACTIVITIES:			
Sales of securities:			
First mortgage bonds	737,298	590,790	650,115
Commercial paper	215,000	—	—
Preferred stock	—	98,625	98,150
Common stock	350,463	399,900	300,150
Retirement of long-term debt and preferred stock	(237,178)	(73,838)	(453,009)
Increase (decrease) in notes payable to parent	(134,000)	(240,750)	374,750
Increase in notes payable to banks	—	35,000	—
Preferred stock dividends paid	(121,610)	(99,719)	(107,694)
Common stock dividends paid	(650,940)	(607,230)	(542,298)
Debt premium, discount and financing expenses	(22,298)	(8,263)	(44,673)
Net cash flows from financing activities	136,7[illegible]5	94,495	275,491
CASH FLOWS FROM (FOR) INVESTING ACTIVITIES:			
Construction expenditures	(1,195,680)	(1,431,647)	(1,7[illegible]3,890)
Allowance for equity funds used during construction (excluding amount for nuclear fuel)	232,068	397,289	331,365
Change in construction receivables/payables — net	(6,074)	(3,606)	(15,506)
Cash construction expenditures	(969,686)	(1,037,964)	(1,478,031)
Non-utility property — net	(27)	(69)	(79)
Nuclear fuel (excluding allowance for equity funds used during construction)	(16,694)	(2,180)	1,606
Purchase of minority ownership interests in Comanche Peak	—	—	(18,000)
Other investments	(11,278)	1,454	(21,103)
Net cash flows from (for) investing activities	(997,685)	(1,038,759)	(1,515,607)
NET CHANGE IN CASH AND CASH EQUIVALENTS	227,157	(482)	(193,850)
CASH AND CASH EQUIVALENTS — BEGINNING BALANCE	4,644	5,126	198,976
CASH AND CASH EQUIVALENTS — ENDING BALANCE	$ 231,801	$ 4,644	$ 5,126

See accompanying Notes to Financial Statements.

TEXAS UTILITIES ELECTRIC COMPANY

BALANCE SHEETS

ASSETS

	December 31, 1991	December 31, 1990
	Thousands of Dollars	
ELECTRIC PLANT		
In service:		
Production	$10,421,387	$10,342,116
Transmission	1,443,565	1,388,959
Distribution	3,377,396	3,190,258
General	425,448	408,294
Total	15,667,796	15,329,627
Less accumulated depreciation	3,392,463	3,026,995
Electric plant in service less accumulated depreciation	12,275,333	12,302,632
Construction work in progr: .s	4,809,088	4,012,241
Nuclear fuel (net of accu ulated amortization — 1991, $25,393,000; 1990, $11,307,000)	333,701	311,416
Held for future use	29,069	28,989
Electric plant less accumulated depreciation and amortization	17,447,191	16,655,278
Less reserve for regulatory disallowances (Note 12)	1,308,460	—
Net electric plant	16,138,731	16,655,278
INVESTMENTS	28,919	17,614
CURRENT ASSETS		
Cash in banks	5,451	4,644
Temporary cash investments	226,350	—
Special deposits	22,171	22,497
Accounts receivable:		
Customers	85,010	58,299
Other	39,840	37,480
Allowance for uncollectible accounts	(2,931)	(2,290)
Inventories — at average cost:		
Materials and supplies	174,977	147,661
Fuel stock	86,068	94,159
Deferred federal income taxes (over-recovered fuel revenue)	—	3,597
Prepaid taxes	10,771	21,501
Other current assets	22,953	35,766
Total current assets	670,660	423,314
DEFERRED DEBITS		
Unamortized regulatory assets:		
Debt reacquisition costs	109,708	99,812
Cancelled lignite unit costs	25,563	30,533
Rate case costs	48,328	48,962
Litigation and settlement costs	72,685	71,991
Under-recovered fuel revenue	32,950	—
Other deferred debits	38,615	39,772
Total deferred debits	327,849	291,070
Less reserve for regulatory disallowances (Note 12)	72,685	—
Net deferred debits	255,164	29[illegible]070
Total	$17,093,474	$17,387,276

See accompanying Notes to Financial Statements.

TEXAS UTILITIES ELECTRIC COMPANY

BALANCE SHEETS

CAPITALIZATION AND LIABILITIES

	December 31, 1991	December 31, 1990
	Thousands of Dollars	
CAPITALIZATION		
Common stock without par value:		
Authorized shares 180,000,000		
Outstanding shares — 1991, 141,125,000; 1990, 134,050,000	$ 4,31[illegible]	$ 3,966,000
Retained earnings	1,424,974	2,486,690
Total common stock equity	5,741,437	6,452,690
Preferred stock:		
Not subject to mandatory redemption	1,007,728	1,007,728
Subject to mandatory redemption	425,758	426,737
Long-term debt, less amounts due currently	7,253,626	6,750,635
Total capitalization	14,428,549	14,637,790
CURRENT LIABILITIES		
Notes payable:		
Parent	—	134,000
Banks	250,000	35,000
Long-term debt due currently	82,522	85,421
Total (to be refinanced)	332,522	254,421
Accounts payable:		
Affiliates	109,288	116,780
Other	149,950	170,565
Dividends declared	30,225	30,638
Customers' deposits	52,159	50,699
Taxes accrued	251,363	174,667
Interest accrued	185,923	178,598
Over-recovered fuel revenue	—	10,579
Other current liabilities	72,862	37,236
Total current liabilities	1,184,292	1,024,163
DEFERRED CREDITS AND OTHER NONCURRENT LIABILITIES		
Accumulated deferred federal income taxes	658,585	895,056
Unamortized federal investment tax credits	727,896	781,426
Other deferred credits and noncurrent liabilities	94,152	48,821
Total deferred credits and other noncurrent liabilities	1,480,633	1,725,303
COMMITMENTS AND CONTINGENCIES (Notes 2 and 13)		
Total	$17,093,474	$17,387,276

See accompanying Notes to Financial Statements.

TEXAS UTILITIES ELECTRIC COMPANY

STATEMENTS OF RETAINED EARNINGS

	Year Ended December 31,		
	1991	1990	1989
	Thousands of Dollars		
BALANCE AT BEGINNING OF YEAR	$2,486,690	$2,247,913	$2,012,747
ADD — NET INCOME (LOSS)	(289,173)	964,276	886,176
Total	2,197,517	3,212,189	2,898,923
DEDUCT			
Cash Dividends:			
Preferred stock:			
$ 4.50 series ($ 4.50 per share per annum)	334	334	334
4.00 series ($ 4.00 per share per annum)	280	280	280
4.56 series ($ 4.56 per share per annum)	609	609	609
4.00 series ($ 4.00 per share per annum)	440	440	440
4.56 series ($ 4.56 per share per annum)	296	296	296
4.24 series ($ 4.24 per share per annum)	424	424	424
4.64 series ($ 4.64 per share per annum)	464	464	[illegible]
4.84 series ($ 4.84 per share per annum)	339	339	339
4.00 [illegible]ries ($ 4.00 per share per annum)	[illegible]80	280	280
4.76 series ($ 4.76 per share per annum)	476	476	476
5.08 series ($ 5.08 per share per annum)	407	407	407
[illegible] series ($ 4.80 per share per annum)	480	480	480
4.44 series ($ 4.44 per share per annum)	666	666	666
7.20 series ($ 7.20 per share per annum)	1,440	1,440	1,440
7.80 series ($ 7.80 per share per annum)	2,339	2,[illegible]39	2,339
8.92 series ($ 8.92 per share per annum)	1,784	1,784	1,784
6.84 series ($ 6.84 per share per annum)	1,368	1,368	1,368
7.24 series ($ 7.24 per share per annum)	1,809	1,809	1,809
7.44 series ($ 7.44 per share per annum)	2,232	2,232	2,232
7.48 series ($ 7.48 per share per annum)	2,244	2,244	2,244
8.20 series ($ 8.20 per share per annum)	2,460	2,460	2,460
8.44 series ($ 8.44 per share per annum)	2,532	2,532	2,532
9.32 series ($ 9.32 per share per annum)	2,796	2,796	2,796
9.36 series ($ 9.36 per share per annum)	2,808	2,808	2,808
8.68 series ($ 8.68 per share per annum)	2,604	2,604	2,604
8.16 series ($ 8.16 per share per annum)	2,444	2,444	2,444
8.32 series ($ 8.32 per share per annum)	2,496	2,496	2,4[illegible]
8.84 series ($ 8.84 per share per annum)	2,652	2,652	2,652
9.48 series ($ 9.48 per share per annum)	9,236	9,236	9,236
8.92 series ($ 8.92 per share per annum)	4,460	4,460	4,460
10.00 series ($10.00 per share per annum)	5,000	5,000	5,000
10.92 series ($10.92 per share per annum)	3,276	3,276	3,276
10.12 series ($10.12 per share per annum)	3,54[illegible]	3,542	3,542
10.08 series ($10.08 per share per annum)	3,140	3,278	3,377
11.32 series ($11.32 per share per annum)	3,396	3,396	3,396
9.64 series ($ 9.64 per share per annum)	9,640	9,640	9,640
10.37[illegible]ies ($10.375 per share per annum)	7,781	5,793	—
9.875 [illegible]eries ($ 9.875 per share per annum)	2,468	555	—
Adjustable rate series A	6,500	6,613	6,637
Adjustable rate series B	6,014	6,162	6,205
Stated rate auction series A	8,240	8,240	8,240
Flexible adjustable rate series A	4,500	4,619	2,980
Flexible adjustable rate series B	4,500	4,619	2,980
Common stock (per share: 1991, $4.80; 1990, $4.68; 1989, $4.56)	650,940	607,230	542,298
Total cash dividends	772,136	725,162	650,770
Dividends other than cash — accretions	407	337	240
Total dividends	772,543	725,499	651,010
BALANCE AT END OF YEAR	$1,424,974	$2,486,690	$2,247,913

See accompanying Notes to Financial Statements.

NOTES TO FINANCIAL STATEMENTS

1. SIGNIFICANT ACCOUNTING POLICIES

Electric Plant — Electric plant is stated at original cost. The cost of property additions to electric plant includes labor and materials, applicable overhead and payroll-related costs and an allowance for funds used during construction.

Allowance For Funds Used During Construction — Allowance for funds used during construction (AFUDC) is a cost accounting procedure whereby amounts based upon interest charges on borrowed funds and a return on equity capital used to finance construction are added to electric plant. The accrual of AFUDC is in accordance with generally accepted accounting principles for the industry, but does not represent current cash income.

Texas Utilities Electric Company (Company) is capitalizing AFUDC, compounded semi-annually, on expenditures for ongoing construction work in progress (CWIP) and nuclear fuel in process not otherwise allowed in rate base by regulatory authorities. In 1989 and 1990, the Company used a net-of-tax rate of 9% on projects commenced before March 1, 1986, and a gross rate of 10.5% on projects commenced thereafter. The net and gross rates were increased for 1991 to 10.4% and 12%, respectively. Rates were determined on the basis of, but are less than, the cost of capital used to finance the construction program.

Depreciation of Electric Plant — Depreciation is generally based upon an amortization of the original cost of depreciable properties (net of regulatory disallowances) on a straight-line basis over the estimated service lives of the properties. Depreciation as a percent of average depreciable property approximated 2.9%, 2.9% and 3.3% for 1991, 1990 and 1989, respectively. Depreciation also includes an amount for Comanche Peak nuclear generating station (Comanche Peak) decommissioning costs which is being accrued over the life of the unit and deposited to an external trust fund. (See Note 13.)

Amortization of Nuclear Fuel — The amortization of nuclear fuel in the reactor (net of regulatory disallowances) is calculated on the units of production method and, subsequent to commercial operation, is included in nuclear fuel expense.

Revenues — Revenues include billings under approved rates (including a fixed fuel factor) applied to meter readings each month on a cycle basis and an amount for under- or over-recovery of fuel revenue representing the difference between actual fuel cost and billings on the approved fixed fuel factor. Beginning in 1992 an accrual will be made for base rate revenues earned but unbilled. Revenues also include a provision that generally allows recovery through a Power Cost Recovery Factor, on a monthly basis, of the capacity portion of purchased power cost from cogenerators not included in base rates. The fuel portion of purchased power cost is included in the fixed fuel factor. Pursuant to a Public Utility Commission of Texas (PUC) rule, the Company is required to refund over-recovered fuel revenue if the amount of over-recovery, including interest, exceeds the lesser of $40 million or 4% of its annual known or reasonably predictable fuel costs most recently approved by the PUC. Reconciliation of fuel costs is to be made in a general rate case or a reconciliation proceeding. Reconciliation may be requested only if it has either been over one year since the utility's last final reconciliation or the utility has materially under-recovered its known or reasonably predictable fuel costs.

1. Significant Accounting Policies — (concluded)

Federal Income Taxes — The Company is included in the consolidated federal income tax return of Texas Utilities Company (Texas Utilities) and its subsidiaries (System Companies), and federal income taxes are allocated to all System Companies based upon their taxable income or loss. Deferred federal income taxes are currently provided for timing differences between book and taxable income (including the provision for regulatory disallowances). Generally, such differences result primarily from the use of liberalized depreciation and cost recovery deductions allowable under the Internal Revenue Code, the under- or over-recovery of fuel revenue and unbilled revenues accrued for tax purposes. Cumulative timing differences in earlier years for which deferred federal income taxes were not provided approximated $203,000,000 at December 31, 1991. Investment tax credits are normally amortized to income over the estimated service lives of the properties. (See Note 8 for pending change in accounting for income taxes.)

Cash Flows — For purposes of reporting cash flows, temporary cash investments purchased with a remaining maturity of three months or less are considered to be cash equivalents.

Supplemental schedules of cash payments and noncash investing and financing activities and are provided below:

	Year End December 31,		
	1991	1990	1989
		Thousands of Dollars	
CASH PAYMENTS:			
Interest (net of amounts capitalized)	$605,845	$456,528	$418,574
Income taxes	70,325	59,390	145,028
NONCASH INVESTING AND FINANCING ACTIVITIES:			
Purchase of minority ownership interests in Comanche Peak:			
Production and transmission plant	$ —	$183,501	$ —
Nuclear fuel	—	13,709	—
Reimbursement of certain expenses (deferred debits) and working funds advanced	—	32,695	—
Total purchase price	—	229,905	—
Plus financing charges	—	8,634	—
Less amounts due from minority owners	—	45,818	—
Less promissory note, obligation and debt assumed	—	174,721	—
Less payment made in prior period	—	18,000	—
Cash paid on the purchase	$ —	$ —	$ —

2. Affiliates

Texas Utilities provides common stock capital and partial requirements for short-term financing to the Company. Texas Utilities has three other subsidiaries which perform specialized services for the System Companies, including the Company: Texas Utilities Services Inc. provides financial, accounting, computer, telecommunications, shareholder services and other administrative services at cost; Texas Utilities Fuel Company (Fuel Company) owns a natural gas pipeline system, acquires, stores and delivers fuel gas and provides other fuel services at cost for the generation of electric energy by the Company; and Texas Utilities Mining Company (Mining Company) owns, leases and operates fuel production facilities for the surface mining and recovery of lignite at cost for use at the Company's generating stations.

2. AFFILIATES — (concluded)

The Company has entered into agreements with Fuel Company to procure certain fuels and related services and with Mining Company for the procurement and production of lignite; payments are at cost for the services received and are required by the agreements to be "at least equivalent in the aggregate to the annual charge to income on the books" of Fuel Company and of Mining Company. The Company is, in effect, obligated for the principal, $404,940,000 at December 31, 1991, and interest on long-term notes of Fuel Company and of Mining Company through payments described above. Such notes mature at various dates through 2001 and have interest rates ranging from 8.50% to 10.85%.

3. SHORT-TERM FINANCING

The Company and Texas Utilities have joint lines of credit aggregating $1,025,000,000 under a credit facility agreement with a group of commercial banks. The facility, for which Texas Utilities pays a fee, will be reduced in 1993, 1994 and 1995 by $325,000,000, $350,000,000 and $350,000,000, respectively. This credit facility may be used to finance new construction, as backup for commercial paper and for general corporate purposes. At December 31, 1991, the Company had $250,000,000 outstanding under this credit facility. From time to time Texas Utilities makes short-term loans to the Company.

4. COMMON STOCK

The Company issued and sold shares of its authorized but unissued common stock to Texas Utilities as follows: December 1991, 3,950,000 shares for $200,463,000; June 1991, 3,125,000 shares for $150,000,000; May 1990, 8,600,000 shares for $399,900,000; December 1989, 6,525,000 shares for $300,150,000.

No shares of the Company's common stock are held by or for account of the Company, nor are any shares of such capital stock reserved for officers and employees or for options, warrants, conversions and other rights in connection therewith.

5. PREFERRED STOCK (cumulative, without par value, entitled upon liquidation to $100 a share; authorized 17,000,000 shares)

Series Groups		Shares Outstanding December 31,		Amount December 31,		Redemption Price Per Share (Before Adding Accumulated Dividends)			
						Current		Eventual Minimum	
From	To	1991	1990	1991	1990	From	To	From	To
				Thousands of Dollars					
Not Subject to Mandatory Redemption									
$4.00	$ 4.84	1,142,942	1,142,942	$ 114,588	$ 114,588	$101.79	$112.00	$101.79	$112.00
5.08	7.80	1,629,675	1,629,675	163,270	163,270	102.40	103.60	102.40	103.60
8.16	8.92	1,999,475	1,999,475	198,642	198,642	101.92	104.09	101.00	103.60
9.32	11.32	1,550,000	1,550,000	153,205	153,205	102.33	107.55	100.00	102.73
Adjustable rate (a)		1,850,000	1,850,000	181,713	181,713	103.00	103.00	100.00	100.00
Stated rate auction (b)		1,000,000	1,000,000	98,164	98,164	—	—	100.00	100.00
Flexible adjustable rate (c)		1,000,000	1,000,000	98,146	98,146	—	—	100.00	100.00
Total		10,172,092	10,172,092	$1,007,728	$1,007,728				

5. PREFERRED STOCK (cumulative, without par value, entitled upon liquidation to $100 a share; authorized 17,000,000 shares) — (continued)

Series Groups From	Series Groups To	Shares Outstanding December 31, 1991	Shares Outstanding December 31, 1990	Amount December 31, 1991 (Thousands of Dollars)	Amount December 31, 1990 (Thousands of Dollars)	Redemption Price Per Share (Before Adding Accumulated Dividends) Current From	Current To	Eventual Minimum From	Eventual Minimum To
Subject to Mandatory Redemption (d)(e)									
$8.92	$ 9.48	1,474,250	1,474,250	$ 146,781	$ 146,661	$103.00	$105.00	$100.00	$100.00
9.64	10.375	2,808,000	2,822,000	278,977	280,076	105.00	107.56	100.00	100.00
Total		4,282,250	4,296,250	$ 425,758	$ 426,737				

(a) Adjustable rate series A bears a dividend rate for the period ended January 31, 1992, of 6.50% per annum and adjustable rate series B bears a dividend rate for the period ended December 31, 1991, of 7.00% per annum, both of which are based on a fixed liquidation price of $100 per share.

(b) Stated rate auction series A bears a dividend rate of 8.24% per annum for the fixed dividend period through September 30, 1992, based on a fixed liquidation price of $100 per share. The dividend rate for each 49 day dividend period thereafter will be determined on the basis of certain auction procedures. All redemptions are at a price of $100 per share plus accumulated dividends. The shares are not redeemable prior to September 29, 1992.

(c) Flexible adjustable rate series A and B bear a dividend rate for the period ended December 31, 1991 of 8.80% per annum, based on a fixed liquidation price of $100 per share. The shares will continue to bear an adjustable dividend rate, based on the rates of certain U. S. Treasury securities, through June 30, 1993. During this initial period, under certain circumstances relating to a change in federal tax law governing the dividends received deduction applicable to eligible corporations, the dividend rate may increase or decrease accordingly. In no case will the per annum dividend rate during this initial period be greater than 14% or less than 7%. After June 30, 1993, dividends will be determined on the basis of certain auction procedures. The shares are not redeemable before June 30, 1993, unless a change in the federal tax law governing the dividends received deduction occurs, at which time the shares may be redeemed on any quarterly dividend payment date through April 30, 1993.

(d) The Company is required to redeem at a price of $100 per share plus accumulated dividends a specified minimum number of shares annually or semi-annually occurring on the initial/next dates shown below, except for the $8.92 series which does not have a sinking fund provision. These redeemable shares may be called, purchased or otherwise acquired. Certain issues may not be redeemed prior to 1995. The Company may annually call for redemption, at its option, an aggregate of up to twice the number of shares shown below for each series at a price of $100 per share plus accumulated dividends, except for the $9.64 series which may be redeemed in a minimum amount of 10,000 shares at any time at a price of $100 per share plus accumulated dividends plus a component at a variable price per share which is designed to maintain the expected yield at issuance:

Series	Minimum Redeemable Shares	Initial/Next Date of Mandatory Redemption
$10.08	14,000 annually	4/1/92
9.48	66,700 annually	4/1/92
10.00	20,000 annually	7/1/92
9.64	125,000 semi-annually	5/1/95
10.375	150,000 annually	4/1/96
8.92	All outstanding shares	7/1/96
9.875	50,000 annually	10/1/96

The carrying value of preferred stock subject to mandatory redemption is being increased periodically to equal the redemption amounts at the mandatory redemption dates with a corresponding increase in preferred stock dividends. At December 31, 1991, 25,750 shares of the $9.48 series had been purchased by the Company and will be applied to the redemption requirements shown above.

(e) Under certain circumstances relating to a change in federal tax law governing the dividends received deduction applicable to eligible corporations, the dividend rate of the $9.64 series may increase to a maximum of $10.74.

5. **PREFERRED STOCK (cumulative, without par value, entitled upon liquidation to $100 a share; authorized 17,000,000 shares) — (concluded)**

In 1991, the Company redeemed 14,000 shares of its $10.08 series which fulfills its mandatory redemption requirements until April 1, 1992.

The Company issued and sold shares of its authorized preferred stock as follows: October 1990, 250,000 shares of $9.875 series, subject to mandatory redemption, for $24,531,250; April 1990, 750,000 shares of $10.375 series, subject to mandatory redemption, for $74,093,750 and May 1989, 1,000,000 shares of flexible adjustable rate series A and B, for $98,150,000.

6. RETAINED EARNINGS RESTRICTIONS

The Company's articles of incorporation, the mortgages, as supplemented, and the debenture agreements contain provisions which, under certain conditions, restrict distributions on or acquisitions of its common stock. At December 31, 1991, $178,007,000 of retained earnings were thus restricted as a result of the provisions of such articles of incorporation.

The articles of incorporation restriction provides in effect that the Company shall not pay any common dividend which would reduce retained earnings to less than one and one-half times annual preferred dividend requirements. The mortgage restrictions are based primarily on the replacement fund requirements of the mortgages. The restriction contained in the debenture agreements is designed to maintain the aggregate preferred and common stock equity at or above 33-1/3% of total capitalization.

7. LONG-TERM DEBT, less amounts due currently

Maturity Groups From	Maturity Groups To	Interest Rate Groups From	Interest Rate Groups To	December 31, 1991	December 31, 1990
				Thousands of Dollars	
First mortgage bonds:					
1993	1997	4-1/4%	9-1/2%	$ 356,000	$ 356,000
1998	2002	6-5/8	10-3/8	690,000	690,000
2003	2007	7-1/2	10-1/8	750,000	750,000
2008	2012	9-3/8	11-5/8	400,000	400,000
2013	2017	9-1/4	12	1,675,000	1,825,000
2018	2021	9-3/4	11-3/8	950,000	650,000
Pollution control series:					
2007	2021	7-3/4	10	990,000	890,000
Funds on deposit with trustee				—	(5,298)
Taxable pollution control series: (a)					
—	2021	Various		275,000	—
Sinking fund debentures:					
1993	1994	6-5/8	7-3/4	29,053	29,915
Secured medium-term notes, series A through C:					
1994	2003	8.72	10.50	600,000	543,000
Total				6,715,053	6,128,617
Pollution control revenue bonds:					
2004	2009	5.70	7-5/8	158,930	160,000
Promissory note, obligation and debt assumed for purchase of electric plant:(b)					
1993	2021	8.25	9.73	437,773	518,721
Unamortized premium and discount				(58,130)	(56,703)
Total long-term debt, less amounts due currently				$7,253,626	$6,750,635

(a) Taxable pollution control series consist of four series: $75,000,000 of Series 1991A at 7.25% through June 1, 1992; $50,000,000 of Series 1991B at 8.10% through June 1, 1993; $50,000,000 of Series 1991C at 8.49% through June 1, 1994; and $100,000,000 of Series 1991D at 8.85% through June 1, 1995. The interest rates on such bonds will be repriced at various mandatory tender dates beginning in 1992. The Company has existing lines of credit to allow refinancing of the bonds on a long-term basis should remarketing prove unsuccessful.

(b) In 1988, the Company purchased the ownership interest in Comanche Peak of Brazos Electric Power Cooperative and issued a promissory note payable over 33 years. The note is secured by a mortgage on the acquired interest. Also in 1988, the Company purchased the ownership interest in Comanche Peak of the Texas Municipal Power Agency under an installment sale agreement obligating the Company to make semi-annual payments through 1993. The transaction is treated as a completed purchase of electric plant; however, under terms of the agreement, legal title to the purchased assets passes to the Company at the time of, and in proportion to, each payment made. In 1990, the Company purchased the ownership interest in Comanche Peak of Tex-La Electric Cooperative of Texas, Inc. (Tex-La) and assumed debt of Tex-La payable over approximately 32 years. The assumption is secured by a mortgage on the acquired interest. Texas Utilities has guaranteed these various payments.

7. LONG-TERM DEBT, less amounts due currently — (concluded)

Sinking fund and maturity requirements for the years 1992 through 1996 under long-term debt instruments in effect at December 31, 1991, were as follows:

Year	Sinking Fund(a)	Maturity(b)	Minimum Cash Requirement(c)
	Thousands of Dollars		
1992	$101,683	$ —	$ 82,522
1993	65,682	117,011	164,708
1994	24,314	140,500	147,193
1995	24,364	80,000	87,153
1996	24,176	96,000	103,652

(a) Excluding requirements satisfied prior to December 31, 1991: $1,327,500 for 1992.

(b) The maturity requirements do not include the mandatory tenders of the Company's taxable pollution control series, equal to $75,000,000 in 1992, $50,000,000 in 1993, $50,000,000 in 1994 and $100,000,000 in 1995, which are expected to be remarketed.

(c) Other requirements may be satisfied by certification of property additions at the rate of 167% of such requirements, except for sixteen issues at 100%.

From time to time, various principal amounts of first mortgage bonds have been redeemed by the Company prior to maturity. The debt reacquisition costs have been deferred and are being amortized over the remaining lives of the bonds retired.

8. Federal Income Taxes

The details of federal income taxes are as follows:

	Year Ended December 31,		
	1991	1990	1989
	Thousands of Dollars		
Charged (credited) to operating expenses:			
Current	$ 80,751	$ 56,828	$117,248
Deferred — net:			
Differences between depreciation methods and lives	222,766	155,587	44,537
Certain capitalized construction costs	2,706	4,601	18,198
Over/under-recovered fuel revenue	14,800	18,259	(11,115)
Early redemptions of long-term debt	3,364	(1,736)	12,031
Prepaid (accrued) pension cost	(3,858)	2,942	5,999
Unbilled revenues	277	(14,165)	(20,965)
Minority owners settlement	190	5,971	—
Alternative minimum tax	(111,379)	(80,162)	(42,895)
Investment tax credit carryforward	16,243	(37,171)	—
Amortization of tax rate differences	(20,336)	(10,083)	—
Provision for refund and related interest — net	(15,541)	—	—
Prior year adjustments	(18,883)	(1,562)	(9,568)
Other	(4,819)	2,910	7,029
Total	85,530	45,391	3,251
Investment tax credits — net	(13,318)	33,841	26,090
Total to operating expenses	152,963	136,060	146,589
Charged (credited) to other income:			
Current	(4,678)	1,102	2,113
Deferred — net:			
Provision for regulatory disallowances	(327,178)	—	—
Amortization of regulatory disallowances	8,787	—	—
Other	397	333	96
Total	(317,994)	1,435	2,209
Investment tax credits — regulatory disallowances	(40,160)	—	—
Total to other income	(362,852)	1,435	2,209
Total federal income taxes	$(209,889)	$137,495	$148,798

8. FEDERAL INCOME TAXES — (concluded)

Federal income taxes were less than the amount computed by applying the federal statutory rate to pre-tax book income (loss) as follows:

	Year Ended December 31,		
	1991	1990	1989
	Thousands of Dollars		
Federal income taxes at statutory rate of 34%	$(169,681)	$374,602	$351,891
Reductions in federal income taxes resulting from:			
Allowance for funds used during construction	118,603	207,702	171,452
Depletion allowance	21,104	24,975	22,523
Amortization of investment tax credits	20,401	16,647	13,848
Amortization of tax rate differences	20,336	10,083	—
Reversal of prior book/tax differences:			
Provision for regulatory disallowances	(142,412)	—	—
Investment tax credit — regulatory disallowances	40,180	—	—
Other	(23,278)	(11,816)	(4,360)
Prior year adjustments	(11,694)	389	2,060
Other	(3,032)	(10,873)	(2,430)
Total reductions	40,208	237,107	203,093
Total federal income taxes	$(209,889)	$137,495	$148,798
Effective tax rate	42.1%	12.5%	14.4%

In February 1992, the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standards No. 109, "Accounting for Income Taxes", which is effective for fiscal years beginning after December 15, 1992. The Statement, among other things, requires the liability method of recognition for all temporary differences, requires that deferred tax liabilities and assets be adjusted for an enacted change in tax laws or rates and prohibits net-of-tax accounting and reporting. Certain provisions of the Statement provide that regulated enterprises are permitted to recognize such adjustments as regulatory assets or liabilities if it is probable that such amounts will be recovered from or returned to customers in future rates. Although application of the Statement will increase both total assets and liabilities, these requirements are not expected to have a material effect on the Company's financial position or results of operations.

9. RETIREMENT PLAN AND OTHER POSTRETIREMENT BENEFITS

The Company has a retirement plan covering substantially all employees. An employee's benefits are based on years of accredited service and average annual earnings received during the three years of highest earnings. The costs of the plan were determined by independent actuaries. Contributions to the plan were determined using the frozen attained age method which is one of the several actuarial methods allowed by the Employee Retirement Income Security Act of 1974. For financial reporting purposes, pension cost has been determined using the projected unit credit actuarial method. The cumulative difference between pension cost as determined for financial reporting purposes and contributions to the plan is recorded either as prepaid pension cost or as accrued pension liability.

9. RETIREMENT PLAN AND OTHER POSTRETIREMENT BENEFITS — (continued)

The following table sets forth the plan's funded stat nd amount recognized in the Company's balance sheets:

	December 31,	
	1991	1990
	Thousands of Dollars	
Actuarial present value of accumulated benefits:		
Accumulated benefit obligation (including vested benefits of $584,120,000 for 1991 and $505,257,000 for 1990)	$(622,537)	$(531,840)
Projected benefit obligation for service rendered to date	$(760,502)	$(680,309)
Plan assets at fair value, primarily equity investments, government bonds and corporate bonds	995,740	828,348
Plan assets in excess of projected benefit obligation	235,238	148,039
Unrecognized net gain from past experience different from that assumed and effects of changes in assumptions	(241,433)	(117,533)
Prior service cost not yet recognized in net periodic pension expense	21,949	(2,717)
Unrecognized plan assets in excess of projected benefit obligation at initial application	(8,660)	(9,348)
Prepaid pension cost	$ 7,094	$ 18,441

Assumptions used in determination of the projected benefit obligation include the following:

	1991	1990
Discount rate	8.50%	8.50%
Increase in compensation levels	5.30	5.30

Total pension costs, including amounts charged to fuel cost and capitali vere comprised of the following components:

	Year Ended December 31,		
	1991	1990	1989
	Thousands of Dollars		
Service cost — benefits earned during the period	$ 23,860	$ 22,231	$ 21,150
Interest cost on projected benefit obligation	58,118	53,048	50,522
Actual return on plan assets	(207,126)	13,628	(149,941)
Net amortization and deferral	136,494	(81,767)	90,259
Total pension cost	$ 11,346	$ 7,140	$ 11,990

The assumed long-term rate of return on plan assets was 8.75% for 1991, 1990 and 1989.

Effective January 1, 1989, vesting in the retirement plan was reduced from 10 years to 5 years.

In addition to the retirement plan, the Company offers certain health care and life insurance benefits to active and retired employees. The costs of such benefits are generally recognized as claims are paid. The costs of providing such benefits to retired employees, net of employee contributions, approximated $13,781,000 for 1991, $12,342,000 for 1990 and $10,639,000 for 1989.

9. Retirement Plan and Other Postretirement Benefits — (concluded)

In December 1990, the FASB issued Statement of Financial Accounting Standards No. 106, "Employers' Accounting for Postretirement Benefits Other Than Pensions", which is effective for fiscal years beginning after December 15, 1992. The Statement requires a change in the accounting for a company's obligation to provide health care and certain other benefits to its retirees from the "pay-as-you-go" method to an accrual method and requires the cost of the obligation to be recognized in the period from employment date until full eligibility for benefits. The Company currently estimates that the unfunded actuarial present value of employee service rendered to the expected date of adoption (transition obligation at January 1, 1993), to be approximately $210 million to $260 million. The Statement allows the transition obligation to be either recognized immediately as the cumulative effect of a change in accounting principle or amortized evenly over the longer of the average remaining service lives of covered employees or 20 years. The Company expects to recognize the transition obligation over the average remaining service lives of covered employees. The total annual benefits cost is estimated to be approximately $35 million to $50 million. The Company expects that the accrual of benefits cost will either be recovered currently through rates, similar to retirement plan costs, or, pursuant to certain provisions of the Statement, that a regulatory asset will be recorded to reflect amounts, if any, whose future recovery is probable through rates as costs are paid. Therefore, this Statement is not expected to have a material effect on the Company's financial position or results of operations.

10. Sales of Accounts Receivable

In 1989, the Company entered into a five year agreement with certain financial institutions whereby the Company is entitled to sell and such financial institutions are required to purchase, on an ongoing basis, up to an aggregate of $300,000,000 of undivided interests in customer accounts receivable. Additional receivables are continually sold to replace those collected. At December 31, 1991 and 1990, $200,000,000 of such receivables were owned by financial institutions.

11. Comanche Peak Nuclear Generating Station

The Company is operating one nuclear-fueled generating unit and constructing a second unit at Comanche Peak, each of which is designed for a capability of 1,150 megawatts. The Company owns all of the plant. (See Note 7.)

The Company is subject to the jurisdiction of the Nuclear Regulatory Commission (NRC) with respect to nuclear power plants. NRC regulations govern the granting of licenses for the construction and operation of nuclear power plants and subject such plants to continuing review and regulation. In April 1990, the NRC issued a full power operating license for Unit 1. The construction permit for Unit 2 is in effect and has been extended until a "latest date for completion" of August 1, 1992. The Company has filed an application with the NRC to extend this construction permit for a sufficient period of time to allow for completion of the unit and expects to obtain approval for the extension.

In July 1988, NRC proceedings before an Atomic Safety and Licensing Board, which involved an intervenor, were dismissed pursuant to a joint motion for dismissal filed by the Company, the intervenor and the NRC Staff. Under the terms of this motion, a representative of the intervenor was appointed as a member of the Operations Review Committee (ORC) for Comanche Peak. The ORC is required by the Comanche Peak technical specifications and reviews operational and other safety related matters.

11. COMANCHE PEAK NUCLEAR GENERATING STATION — (concluded)

At various times in the past, the Company has paid civil penalties to the NRC for violations of NRC regulatory requirements.

Unit 1 and common facilities were placed in commercial operation on August 13, 1990, and Unit 2 is scheduled for service for the peak season of 1993. At December 31, 1991, the Company had $3.479 billion invested in Unit 2 (net of $485 million included in the reserve for regulatory disallowances required by the PUC order), including AFUDC. The estimated cash requirements in 1992 and 1993 to complete Unit 2 are approximately $450 million in the aggregate. Due to the uncertainty of regulatory treatment and the exact month of completion, no estimate for AFUDC accruals on Unit 2 is included. Such accrual approximated $23 million for December 1991.

12. RATE INCREASE

In January 1990, the Company made applications to the PUC and to its municipal regulatory authorities for upward adjustments in rates for electric service throughout its service area which would increase operating revenues by approximately $442 million, or 10.2%, based upon the test year ended June 30, 1989. Such request reflected costs associated with the commercial operation of Unit 1 of Comanche Peak. On August 13, 1990, pursuant to rules of the PUC, the Company placed its requested rate increase into effect applicable to energy sales on or after such date.

In August 1991, the PUC issued a final order in the rate case. This order was revised and reissued in September 1991. The order provided for a total revenue increase of approximately $442 million and included $695 million of CWIP in rate base to support the revenue increase. It also included a prudence disallowance of $472 million with respect to certain Comanche Peak costs relating to 87.8% of the Company's ownership interest in both units of Comanche Peak. With respect to the Company's reacquisition of the remaining 12.2% minority owner interest in Comanche Peak, the order included an additional disallowance of $909 million. In addition, the order provides for refunds aggregating $56 million, including interest, principally with respect to fuel gas costs considered imprudent by the PUC. Such amount is being refunded to customers, with interest, over a two year period that began in November 1991.

The Company strongly disagrees with the order and in November 1991 filed a petition in the 250th Judicial District Court of Travis County, Texas, requesting a reversal and remand of the order. Other parties to the PUC proceeding have also filed appeals with respect to various portions of the order. The Company is unable to predict the outcome of these appeals.

In September 1991, the Company recorded a charge against earnings, as a provision for regulatory disallowances, of $1.381 billion ($1.011 billion after tax) as a result of the PUC order. The charge is comprised of the $472 million of costs associated with Comanche Peak that were disallowed and the disallowance of $909 million related to the minority owner reacquisitions. Also, the Company recorded a charge of $56 million, including interest ($37 million after tax), representing principally fuel gas costs disallowed by the order. As a result, the Company will be precluded from incurring certain forms of debt and issuing preferred stock for a period of approximately twelve months from the date of recording such disallowances.

12. RATE INCREASE — (continued)

The following schedule details the components of the charges and their effect on net income (loss):

	Provision for Regulatory Disallowances	Provision for Refunds and Related Interest	Total
	Thousands of Dollars		
OPERATING REVENUES	$ —	$(36,584)	$ (36,584)
OPERATING EXPENSES			
Operating expenses excluding federal income tax	(4,213)	—	(4,213)
Federal income taxes — deferred	1,432	(19,165)	(17,733)
OPERATING INCOME	2,781	(17,419)	(14,638)
OTHER INCOME (LOSS)			
Provision for regulatory disallowances	(1,381,145)	—	(1,381,145)
Federal income taxes — deferred	327,178	—	327,178
Federal income taxes — investment tax credits	40,180	—	40,180
Total other income (loss)	(1,013,787)	—	(1,013,787)
TOTAL INCOME	(1,011,006)	(17,419)	(1,028,425)
OTHER INTEREST	—	19,678	19,678
EFFECT ON NET INCOME (LOSS)	$(1,011,006)	$(37,097)	$(1,048,103)

Pending the outcome of the appeal, the disallowed C[illegible]anche Peak related costs are reflected as reserves for regulatory disallowances on the Company's balan[illegible]et.

In August 1990, the Company ceased AFU[illegible] accruals and began depreciation provisions on approximately $1.3 billion of investment in Comanche [illegible]ak Unit 1, incurred after the end of the June 30, 1989 test year. Depreciation and rate of return on this investment is not provided for in current electric service rates but will be included in the next rate increase request of the Company. As a result, the Company's earnings and liquidity will continue to be affected until the investment incurred subsequent to the end of the test year is included in rates.

Unit 2 [illegible] Comanche Peak is scheduled for operation for the peak season of 1993 and the Company believes it will be necessary to request additional rate relief from its regulatory authorities, the amount and exact timing of which is presently undetermined. Upon commencement of operation of Unit 2, the Company currently expects to cease accrual of AFUDC on the Unit 2 investment that exceeds the $695 million included in rate base ($23 million of AFUDC for the month of December 1991); begin depreciation accruals on the accumulated investment in Unit 2 ($3.479 billion at December 31, 1991) and to incur operation and maintenance expenses on the generating unit; all of which are not currently included in the Company's present electric service rates.

A request to place additional amounts of Comanche Peak investment in rate base will be subject to a review by the PUC for prudence of costs incurred. In connection with the September 1991 rate order, the PUC essentially reviewed costs incurred through June 1989 on Unit 2 and through fuel load in February

12. RATE INCREASE — (concluded)

1990 on Unit 1. At December 31, 1991, the Company had approximately $1.8 billion invested in Comanche Peak that had not been reviewed for prudence. The Company cannot predict the outcome of any future prudence review.

13. COMMITMENTS AND CONTINGENCIES

Construction Program

Construction expenditures, excluding AFUDC, for the years 1992 through 1994 are estimated at $740,000,000, $664,000,000 and $837,000,000, respectively. The effects of inflation, additional regulatory requirements, revisions in the expected demand growth or other unknown factors could affect estimated completion costs and in service dates of generating units under construction. Commitments in connection with the construction program are generally revocable subject to reimbursement to manufacturers for expenditures incurred or other cancellation penalties.

Clean Air Act

In November 1990, the federal Clean Air Act Amendments of 1990 (Clean Air Act) were enacted which, among other things, placed limits on the sulfur dioxide emissions produced by generating units. The Clean Air Act requires that fossil-fueled plants meet new sulphur dioxide emission standards by 1995 (Phase I) and additional sulfur dioxide emission standards by 2000 (Phase II). The Company's generating units are not affected by the Phase I requirements. The Phase II requirements are currently met by all but four of the Company's generating units. Because the sulfur dioxide emissions from these four units are relatively low and alternatives are available to enable these units to reduce sulphur dioxide emissions, compliance with the applicable Phase II sulfur dioxide requirements is not expected to have a significant impact on the Company.

The Company has not finalized a compliance plan due to the uncertainty of the requirements which the Environmental Protection Agency (EPA) may include in its regulations. The Company intends to utilize internal allocation of emission allowances within its system and, if necessary, to purchase emission allowances to enable both existing and future electric generating units to meet the requirements of the Clean Air Act. The Company is unable to predict the extent to which it may generate excess allowances or will be able to acquire allowances from others if needed.

Other provisions of the Clean Air Act may require the Company to take other actions. The Company's lignite-fired generating units currently meet the required nitrogen oxide limits in the Clean Air Act. The requirements of the Clean Air Act for ozone nonattainment areas may require nitrogen oxide emission reductions at the Company's natural gas-fired units in the Dallas-Fort Worth area by 1996. The Clean Air Act also requires studies over a four year period by the EPA to assess the potential for toxic emissions from utility boilers. The Company is unable to predict whether any reductions in toxic emissions will ultimately be required. Continuous emission monitoring systems are required by the Clean Air Act to be installed by 1995 on all of the Company's fossil-fueled units.

Only certain parts of the regulations implementing the Clean Air Act have been adopted. Until more of these regulations have been promulgated, the Company will not be able to fully determine the cost or

13. COMMITMENTS AND CONTINGENCIES — (continued)

method of compliance for these requirements. The Company believes that it can meet the requirements necessary to be in compliance with these provisions as they are developed. Capital requirements related to the Clean Air Act are included in the Company's construction program. Any additional capital costs, as well as any increased operating costs associated with new requirements or compliance measures, are expected to be recovered through rates, as similar costs have been recovered in the past.

Purchased Power Contracts

The Company has entered into purchased power contracts to purchase portions of the generating output of certain cogenerators and small power producers through the year 2005. These contracts provide for capacity payments subject to a facility meeting certain operating standards and energy payments based on the actual power taken under the contracts. The cost of these purchased power contracts is recovered currently through base rates, power cost and fuel recovery factors applied to customer billings. Capacity payments under these contracts for the years ended December 31, 1991, 1990 and 1989 were $229,953,000, $226,083,000 and $185,236,000, respectively.

Assuming operating standards are achieved, future capacity payments under the agreements are estimated as follows:

Years	Total Thousands of Dollars
1992	$ 240,342
1993	249,109
1994	244,799
1995	238,513
1996	228,337
Thereafter	1,136,450
Total	$2,337,550

Leases

The Company has entered into operating leases covering various facilities and properties including such items as transportation, data processing equipment, office space and combustion turbines. Operating lease agreements were entered into in late 1987 and in December 1989 on certain combustion turbine generating units, each with an initial lease term of approximately 27 years. Lease costs charged to operation expense for the years ended December 31, 1991, 1990 and 1989 were $60,085,000, $51,783,000 and $37,016,000, respectively.

13. COMMITMENTS AND CONTINGENCIES — (continued)

The Company's future minimum lease commitments under such operating leases that have initial or remaining noncancelable lease terms in excess of one year as of December 31, 1991, were as follows:

Years	Combustion Turbines	Other	Total
		Thousands of Dollars	
1992	$ 28,348	$14,897	$ 43,245
1993	28,347	12,052	40,399
1994	28,345	5,836	34,181
1995	28,345	3,200	31,545
1996	28,627	2,127	30,754
Thereafter	697,203	8,085	705,288
Total minimum lease commitments	$839,215	$46,197	$885,412

Cooling Water Contracts

The Company has entered into contracts with public agencies to purchase cooling water for use in the generation of electric energy. In connection with certain contracts, the Company has agreed, in effect, to guarantee the principal, $41,885,000 at December 31, 1991, and interest on bonds issued to finance the reservoirs from which the water is supplied. The bonds mature at various dates through 2011 and have interest rates ranging from 5-1/2 to 7%. The Company is required to make periodic payments equal to such principal and interest for the years 1992 through 1996 as follows: $3,826,000 for 1992, $4,422,000 for 1993, $4,423,000 for 1994, $4,431,000 for 1995 and $4,430,000 for 1996. Payments made by the Company, net of amounts assumed by a third party under such contracts, for 1991, 1990 and 1989 were $2,596,000, $3,437,000 and $3,210,000, respectively. In addition, the Company is obligated to pay certain variable costs of operating and maintaining the reservoirs. The Company has assigned to a municipality all contract rights and obligations of the Company in connection with $94,240,000 remaining principal amount of bonds at December 31, 1991, issued for similar purposes which had previously been guaranteed by the Company. The Company is, however, contingently liable in the unlikely event of default by the municipality.

Nuclear Insurance

With regard to liability coverage, the Price-Anderson Act (Act), as most recently amended in 1988 to extend its effectiveness through 2002, was enacted by Congress to provide financial protection for the public in the event of a significant nuclear power plant incident. The Act sets the statutory limit of public liability for a single nuclear incident currently at $7.8 billion and requires nuclear power plant operators to provide financial protection for this amount. As required, the Company provides this financial protection for a nuclear incident at Comanche Peak resulting in public bodily injury and property damage through a combination of private insurance and industry-wide retrospective payment plans. As the first layer of financial protection, the Company has purchased $200 million of liability insurance from American Nuclear Insurers (ANI), which provides such insurance on behalf of two major stock and mutual insurance pools, Nuclear Energy Liability Insurance Association and Mutual Atomic Energy Liability Underwriters. The second layer of financial protection is provided under an industry retrospective payment program called Secondary Financial Protection (SFP). Under the SFP, each

13. COMMITMENTS AND CONTINGENCIES — (concluded)

operating licensed reactor in the United States is subject to an assessment of up to $66.15 million in the event of a nuclear incident at any nuclear plant in the United States. Assessments are limited to $10 million per operating licensed reactor per year per incident and are subject to increases for inflation every five years.

With respect to nuclear decontamination and property damage insurance, NRC regulations require that nuclear plant license-holders maintain not less than $1.06 billion of such insurance and require the proceeds thereof to be used to place a plant in a safe and stable condition, to decontaminate it pursuant to a plan submitted to and approved by the NRC before the proceeds can be used for plant repair or restoration or to provide for premature decommissioning. The Company maintains nuclear decontamination and property damage insurance for Comanche Peak in the amount of $2.515 billion, above which the Company is self-insured. The primary layer of coverage of $500 million is provided by ANI. The remaining coverage includes premature decommissioning coverage and is provided by ANI in the amount of $765 million and Nuclear Electric Insurance Limited (NEIL), a nuclear electric utility industry mutual insurance company, in the amount of $1.25 billion. The Company is subject to a maximum annual assessment from NEIL of $8 million in the event NEIL's losses under this type of insurance for major incidents at nuclear plants participating in this program exceed its accumulated funds and reinsurance.

In conjunction with commercial operation of Comanche Peak Unit 1, the Company began maintaining Extra Expense Insurance through NEIL to cover the additional costs of obtaining replacement power from another source if Comanche Peak Unit 1 is out of service for more than twenty-one weeks as a result of covered direct physical damage. The coverage provides for weekly payments of up to $3.5 million, $2.333 million and $1.167 million for the first, second and third fifty-two week periods of each outage, respectively, after the initial twenty-one week period. The total maximum coverage is $364 million. Under this coverage, the Company is subject to a maximum assessment of $5 million per year.

Nuclear Decommissioning and Disposal of Spent Fuel

The Company has established a reserve (included in accumulated depreciation) for the decommissioning of Comanche Peak Unit 1, whereby decommissioning costs are being recovered from customers over the life of the plant and deposited to an external trust fund (included in other investments). Recovery of these costs began in August 1990, when Comanche Peak Unit 1 began commercial operation. As of December 31, 1991, $11,657,000 has been deposited to the external trust fund for decommissioning. Based on a site-specific study during 1988 using then-current dollars, decommissioning costs for Comanche Peak Unit 1 were estimated to be $193,000,000.

The Company has a contract with the United States Department of Energy for the future disposal of spent nuclear fuel at a cost of one mill per kilowatt-hour of Comanche Peak Unit 1 net generation. The disposal fee is included in nuclear fuel expense.

General

In addition to the above, the Company is involved in various legal and administrative proceedings which, in the opinion of the Company, should not have a material effect upon its financial position or results of operations.

TEXAS UTILITIES ELECTRIC COMPANY

STATEMENT OF RESPONSIBILITY

The management of Texas Utilities Electric Company is responsible for the preparation, integrity and objectivity of the financial statements of the Company and other information included in this report. The financial statements have been prepared in conformity with generally accepted accounting principles. As appropriate, the statements include amounts based on informed estimates and judgments of management.

The management of the Company has established and maintains a system of internal control designed to provide reasonable assurance, on a cost-effective basis, that assets are safeguarded, transactions are executed in accordance with management's authorization and financial records are reliable for preparing financial statements. Management believes that the system of control provides reasonable assurance that errors or irregularities that could be material to the financial statements are prevented or would be detected within a timely period. Key elements in this system include the effective communication of established written policies and procedures, selection and training of qualified personnel and organizational arrangements that provide an appropriate division of responsibility. This system of control is augmented by an ongoing internal audit program designed to evaluate its adequacy and effectiveness. Management considers the recommendations of the internal auditors and independent certified public accountants concerning the Company's system of internal control and takes appropriate actions which are cost-effective in the circumstances. Management believes that, as of December 31, 1991, the Company's system of internal control was adequate to accomplish the objectives discussed herein.

The independent certified public accounting firm of Deloitte & Touche is engaged to audit, in accordance with generally accepted auditing standards, the financial statements of the Company and to issue their report thereon.

/s/ ERLE NYE

Erle Nye, Chairman of the Board
and Chief Executive Officer

/s/ H. JARRELL GIBBS

H. Jarrell Gibbs, Executive Vice President
and Principal Financial Officer

/s/ S. S. SWIGER

S. S. Swiger, Senior Vice President
and Controller

INDEPENDENT AUDITORS' REPORT

Texas Utilities Electric Company:

We have audited the balance sheets of Texas Utilities Electric Company as of December 31, 1991 and 1990, and the related statements of income, retained earnings and cash flows for each of the three years in the period ended December 31, 1991. Our audits also included the financial statement schedules listed in Item 14.(a)2. 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, the financial statements referred to above present fairly, in all material respects, the financial position of the Company at December 31, 1991 and 1990, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 1991, in conformity with generally accepted accounting principles. Also, in our opinion, the financial statement schedules, when considered in relation to the basic financial statements taken as a whole, present fairly in all material respects the information set forth therein.

DELOITTE & TOUCHE

Dallas, Texas
March 13, 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.

Identification of directors, business experience and other directorships:

Name of Officer	Age	Other Positions and Offices Presently Held With the Company (Current Term Expires May 15, 1992)	Date First Elected as Director	Present Principal Occupation or Employment and Principal Business (preceding 5 yrs.), Other Directorships
T. L. Baker	46	Executive Vice President	February 20, 1987	Executive Vice President of the Company; prior thereto, Senior Vice President of the Company.
Tom Blakey	59	Executive Vice President	July 14, 1988	Executive Vice President of the Company; prior thereto, Executive Vice President of Texas Power Division; prior thereto, served in other management positions with Texas Power Division.
J. S. Farrington	57	None	September 17, 1982	Chairman of the Board and Chief Executive Officer of Texas Utilities, the parent company of the Company; prior thereto, President of Texas Utilities; other directorships: Texas Utilities.
H. Jarrell Gibbs	54	Executive Vice President	May 24, 1989	Vice President and Principal Financial Officer of Texas Utilities and Executive Vice President of the Company; prior thereto, Executive Vice President of Texas Electric Service Division; prior thereto, Vice President of the Company; prior thereto, Treasurer and Assistant Secretary of the Company.
Erle Nye	54	Chairman and Chief Executive	September 17, 1982	President of Texas Utilities, prior thereto, Executive Vice President of the Company and Executive Vice President of Texas Utilities; other directorships: Texas Utilities.
Michael D. Spence	50	Executive Vice President	September 17, 1982	Executive Vice President of the Company; prior thereto, President of Generating Division.
W. M. Taylor	49	Executive Vice President	May 20, 1986	Executive Vice President of the Company; prior thereto, President of Dallas Power Division.
E. L. Watson	57	Executive Vice President	February 20, 1987	Executive Vice President of the Company; prior thereto, Senior Vice President of the Company.

Item 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT (Concluded).

Identification of executive officers and business experience:

Name of Officer	Age	Positions and Offices Presently Held (Current Term Expires May 15, 1992)	Date First Elected to Present Offices	Business Experience (Preceding Five Years)
Erle Nye	54	Chairman and Chief Executive	February 20, 1987	President of Texas Utilities; prior thereto, Executive Vice President of the Company and Executive Vice President of Texas Utilities.
T. L. Baker	46	Executive Vice President	October 1, 1991	Senior Vice President of the Company.
Tom Blakey	56	Executive Vice President	October 1, 1991	Executive Vice President of Texas Power Division; prior thereto, served in other management positions with Texas Power Division.
H. Jarrell Gibbs	54	Executive Vice President	October 1, 1991	Vice President and Principal Financial Officer of Texas Utilities; prior thereto, Executive Vice President of Texas Electric Division; prior thereto, Vice President of the Company; prior thereto, Treasurer and Assistant Secretary of the Company.
Michael D. Spence	50	Executive Vice President	October 1, 1991	President of Generating Division.
W. M. Taylor	49	Executive Vice President	October 1, 1991	President of Dallas Power Division.
E. L. Watson	57	Executive Vice President	October 1, 1991	Senior Vice President of the Company.

There is no family relationship between any of the above named executive officers.

Due to a clerical error, the Initial Statements of Beneficial Ownership with respect to shares of preferred stock of the Company, as required by Section 16(a) of the Securities Exchange Act of 1934, were not timely filed by Mr. H. Jarrell Gibbs and Mr. W. M. Taylor. Neither Mr. Gibbs nor Mr. Taylor owns any shares of preferred stock of the Company. Such forms were filed in October 1991.

Item 11. EXECUTIVE COMPENSATION.

The Company paid cash compensation during 1991 to the following executive officers for services in all capacities:

Name of Individual and Number of Persons in Group	Capacity in Which Compensation Was Received	Cash Compensation
Erle Nye	Chairman of the Board and Chief Executive	$493,750(1)
Michael D. Spence	Executive Vice President	285,000(2)
T. L. Baker	Executive Vice President	223,417
E. L. Watson	Executive Vice President	213,333
W. M. Taylor	Executive Vice President	198,750
All executive officers of the Company as a group (7), including those named above.		1,786,416(3)

(1) Consists entirely of compensation paid by Texas Utilities.

(2) In addition to the amounts reported as Cash Compensation, a performance bonus was paid to Mr. Spence in the amount of $40,000.

(3) Includes compensation paid by the Company, Texas Utilities and TU Services. Does not include payments for any portion of the period during which any individual was not an executive officer of the Company.

Under the Employees' Thrift Plan of the Texas Utilities Company System, all employees with at least one year of full time service with any of the System Companies may invest up to 12% of their regular salary or wages in common stock of Texas Utilities, a United States Government Bond fund, a guaranteed fixed income fund, an equity mutual fund or a percentage in each. Employer-corporations make a contribution to each participant's account of 40%, 50% or 60% of the employee's savings, up to the 6% level, depending upon length of service, which amount is invested in the common stock of Texas Utilities. The Plan includes a leveraged employee stock ownership component under which certain shares of common stock acquired by the Plan Trustee from the Company become available, in accordance with a formula, for periodic allocation to participants' accounts to satisfy, in part, the employer-corporations' obligations to make the contributions discussed above. During 1991, employer contributions under this Plan for all executive officers of the Company as a group (7), amounted to $33,001 including contributions made for Messrs. Nye, Spence, Baker, Watson and Taylor in the amounts of $8,000, $1,503, $1,791, $6,139 and $5,725, respectively. Employer contributions are not included in amounts under Cash Compensation in the table above.

Under the Deferred and Incentive Compensation Plan of the Texas Utilities Company System, officers of Texas Utilities and its subsidiaries with a title of Vice President or above may defer a percentage of their compensation not to exceed a maximum percentage determined by the Board of Directors of Texas Utilities for each Plan year and in any event not to exceed 15% of the participant's compensation. For the Plan year 1991 the maximum deferral percentage was 12%. Such deferred compensation is included in amounts reported under Cash Compensation in the table above. The Company makes a matching award equal to 150% of the deferred compensation. In addition, the Company can also make incentive awards. Such matching and incentive awards are subject to forfeiture under certain circumstances. In no event will the sum of all incentive awards in any Plan year exceed 25% of the aggregate compensation of eligible employees. The Company establishes accounts for each participant containing performance units equal in number to the number of shares of common stock purchased by a trustee with an amount of cash equal to the deferred compensation, matching award and any incentive award. On the expiration of the applicable maturity period (three years for incentive awards and five years for deferrals and matching awards) the value of the participants' accounts will be paid in cash. The maturity requirement is waived if the participant dies or becomes totally and permanently disabled. During 1990, the Texas Utilities Board of Directors amended the Plan to waive the maturity requirement and accelerate the distribution of the deferred amounts and matching awards which would have been paid under the Plan in 1992. Incentive awards under the Plan were distributed in 1991 to all executive officers of the Company as a group (7) in the amount of $82,000, including awards distributed to Messrs. Nye, Spence, Baker, Watson and Taylor in the amounts of $25,000, $20,000, $20,000, $7,000 and $5,000, respectively. Such amounts are not included under Cash Compensation in the table above.

Texas Utilities has established a Salary Deferral Program effective April 1, 1991, under which each employee of Texas Utilities and its subsidiaries whose annual salary is $80,000 or more may elect to defer a percentage of their annual salary for a period of seven years, a period ending with the retirement of such employee, or for a combination thereof. Such deferrals may not exceed in the aggregate 10% of such annual salary, provided that no more than 6% may be deferred under the retirement option for the period ending with the retirement of such employee. Such deferred compensation is included in amounts reported under Cash Compensation in the table above. The minimum eligible annual salary amount will be indexed in future years to reflect changes in the consumer price index. The Company will make a matching award, subject to forfeiture under certain circumstances, equal to 100% of the deferred compensation. A trustee will distribute at the end of the applicable maturity period cash equal to the amounts deferred and matching awards plus earnings equal to the greater of the actual earnings of Program assets, or the average interest rate during the applicable maturity period of U.S. Treasury Notes with a maturity of ten years. The distribution of the amounts due under the Program will be in a lump sum if the maturity period is seven years or, if the retirement option was elected, in twenty annual installments. The Company is financing the retirement portion of the Program through the purchase of corporate owned life insurance on the lives of the participants and the proceeds from such insurance are expected to allow the Company to fully recover the cost of the retirement option.

The Company maintains a retirement plan qualified under applicable provisions of the Internal Revenue Code (Code). Annual retirement benefits are computed as follows: for each year of accredited service up to a total of 40 years of service, 1.3% of the first $7,800, plus 1.5% of the excess over $7,800 of average annual earnings received by the participant during their three years of highest earnings. Such benefits are not subject to any reduction for Social Security payments. Amounts reported as cash compensation for specified officers approximate earnings as defined by the retirement plan. As of February 28, 1992, years of accredited service under the plan for Messrs. Nye, Spence, Baker, Watson, and Taylor were 29, 25, 21, 32, and 23, respectively. The table below illustrates the annual benefit payable at retirement under this formula:

3-year average annual earnings	20 years service	30 years service	40 years service
$ 50,000	$ 14,688	$ 22,032	$ 29,376
100,000	29,688	44,532	59,376
200,000	59,688	89,532	119,376
400,000	119,688	179,532	239,376
500,000	149,688	224,532	299,376
600,000	179,688	269,532	359,376
800,000	239,688	359,532	479,376

Item 11. EXECUTIVE COMPENSATION (Concluded).

Benefits payable from a qualified retirement plan are limited by provisions of the Code. The Company maintains a Supplemental Retirement Plan which provides for the payment of retirement benefits calculated in accordance with the foregoing retirement plan formula which would otherwise be limited by the provisions of the Code. The Company has established a trust to retain funds made available by the Company for the payment of all or a portion of the benefits payable under the Supplemental Retirement Plan to certain participants in such Plan. Any benefits not paid from the trust are payable from the Company's general funds.

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

Security ownership of certain beneficial owners at February 28, 1992:

Title of Class	Name and Address of Beneficial Owner	Amount and Nature of Beneficial Ownership	Percent of Class
Common Stock, without par value, of the Company	Texas Utilities Company 2001 Bryan Tower Dallas, Texas 75201	141,125,000 shares sole voting and investment power	100.0%

Security ownership of management at February 28, 1992:

Title of Class	Number of Shares Beneficially Owned*	Percent of Class
Preferred Stock, without par value, of the Company	56	Less than 1%
Common Stock of Texas Utilities (parent)	114,640	Less than 1%

*Amount of shares with respect to which such persons have the right to acquire beneficial ownership:

None.

Item 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS.

None.

PART IV

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

	Page
(a) Documents filed as part of this Report:	
1. Financial Statements (included in Item 8, Financial Statements and Supplementary Data):	
Statements of Income for each of the three years in the period ended December 31, 1991	26
Statements of Cash Flows for each of the three years in the period ended December 31, 1991	27
Balance Sheets, December 31, 1991 and 1990	28
Statements of Retained Earnings for each of the three years in the period ended December 31, 1991	30
Notes to Financial Statements	31
Statement of Responsibility	48
Independent Auditors' Report	49
2. Financial Statement Schedules -	
For each of the three years in the period ended December 31, 1991:	
Schedule V—Electric Plant	62
Schedule VI—Accumulated Depreciation	63
Schedule VIII—Valuation and Qualifying Accounts	64
Schedule IX—Short-term Borrowings	65
Schedule X—Supplementary Information	66

The following financial statement schedules are omitted because of the absence of the conditions under which they are required or because the required information is included in the Financial Statements or notes thereto: I, II, III, IV, VII, XI, XII and XIII.

(b) Reports on Form 8-K:

Reports on Form 8-K filed since September 30, 1991, are as follows:

Date of Report	Items Reported
October 25, 1991	Item 5. OTHER EVENTS
December 23, 1991	Item 5. OTHER EVENTS
February 5, 1992	Item 5. FINANCIAL STATEMENTS AND EXHIBITS

(c) Exhibits:

Exhibits	Previously Filed* With File Number	As Exhibit		Number	Dated
3(a)	2-91002	4(a)	—	Articles of Incorporation of TU Electric.	
3(a)-1	2-91002	4(b)-1	—	Statement of Resolution establishing Thirty-third Series of Preferred Stock of the Company.	
3(a)-2	2-97786	4(b)-2	—	Statement of Resolution establishing Thirty-fourth Series of Preferred Stock of the Company.	
3(a)-3	33-5528	4(b)-3	—	Statement of Resolution establishing Thirty-fifth Series of Preferred Stock of the Company.	

Item 14. EXHIBITS, FINANCIAL STATEMENT SCHEDULES AND REPORTS ON FORM 8-K (Continued).

	Previously Filed*				
Exhibits	With File Number	As Exhibit		Number	Dated
3(a)-4	33-14585	4(b)-4	—	Statement of Resolution establishing Thirty-sixth Series of Preferred Stock of the Company.	
3(a)-5	33-14585	4(b)-5	—	Statement of Resolution establishing Thirty-seventh Series of Preferred Stock of the Company.	
3(a)-6	33-33432	4(b)-6	—	Statement of Resolution establishing Thirty-eighth Series of Preferred Stock of the Company.	
3(a)-7	33-33432	4(b)-7	—	Statement of Resolution establishing Thirty-ninth Series of Preferred Stock of the Company.	
3(a)-8	33-33432	4(b)-8	—	Statement of Resolution establishing Fortieth and Forty-first Series of Preferred Stock of the Company.	
3(a)-9	0-11442 Form 8-K (Apr. 2, 1990)	4	—	Statement of Resolution establishing Forty-second Series of Preferred Stock of the Company.	
3(a)-10	0-11442 Form 8-K (Oct. 2, 1990)	4	—	Statement of Resolution establishing Forty-third Series of Preferred Stock of the Company.	
3(b)			—	Bylaws of TU Electric, as amended.	
4(a)	2-90185	4(a)	—	Mortgage and Deed of Trust, dated as of December 1, 1983, between the Company and Irving Trust Company (now The Bank of New York), Trustee.	
4(a)-1			—	Supplemental Indentures to Mortgage and Deed of Trust:	
	2-90185	4(b)		First	April 1, 1984
	2-92738	4(a)-1		Second	September 1, 1984
	2-97185	4(a)-1		Third	April 1, 1985
	2-99940	4(a)-1		Fourth	August 1, 1985
	2-99940	4(a)-2		Fifth	September 1, 1985
	33-01774	4(a)-2		Sixth	December 1, 1985
	33-9583	4(a)-1		Seventh	March 1, 1986
	33-9583	4(a)-2		Eighth	May 1, 1986
	33-11376	4(a)-1		Ninth	October 1, 1986
	33-11376	4(a)-2		Tenth	December 1, 1986
	33-11376	4(a)-3		Eleventh	December 1, 1986
	33-14584	4(a)-1		Twelfth	February 1, 1987
	33-14584	4(a)-2		Thirteenth	March 1, 1987
	33-14584	4(a)-3		Fourteenth	April 1, 1987
	33-24089	4(a)-1		Fifteenth	July 1, 1987
	33-24089	4(a)-2		Sixteenth	September 1, 1987
	33-24089	4(a)-3		Seventeenth	October 1, 1987
	33-24089	4(a)-4		Eighteenth	March 1, 1988
	33-24089	4(a)-5		Nineteenth	May 1, 19[illegible]8
	33-30141	4(a)-1		Twentieth	September 1, 1988
	33-30141	4(a)-2		Twenty-first	November 1, 1988
	33-30141	4(a)-3		Twenty-second	January 1, 1989

Item 14. EXHIBITS, FINANCIAL STATEMENT SCHEDULES AND REPORTS ON FORM 8-K (Continued).

	Previously Filed*				
Exhibits	With File Number	As Exhibit		Number	Dated
	33-35614	4(a)-1		Twenty-third	August 1, 1989
	33-35614	4(a)-2		Twenty-fourth	November 1, 1989
	33-35614	4(a)-3		Twenty-fifth	December 1, 1989
	33-35614	4(a)-4		Twenty-six	February 1, 1990
	33-39493	4(a)-1		Twenty-seventh	September 1, 1990
	33-39493	4(a)-2		Twenty-eighth	October 1, 1990
	33-39493	4(a)-3		Twenty-ninth	October 1, 1990
	33-39493	4(a)-4		Thirtieth	March 1, 1991
	33-45104	4(a)-1		Thirty-first	May 1, 1991
	33-45104	4(a)-2		Thirty-second	July 1, 1991
4(a)-2				Thirty-third	February 1, 1992
4(b)	2-2801	B-2	—	Mortgage and Deed of Trust, dated as of February 1, 1937, between Dallas Power & Light Company and Old Colony Trust Company, Trustee (The First National Bank of Boston, successor Trustee).	
4(b)-1			—	Supplemental Indentures to Mortgage and Deed of Trust:	
	2-7855	7(a)		First	April 1, 1949
	2-8466	7(a)-2		Second	June 1, 1950
	2-10071	4(b)-3		Third	March 1, 1953
	2-12200	2(b)-1		Fourth	February 1, 1956
	2-77857	4(b)-5		Fifth	December 1, 1956
	2-77857	4(b)-6		Sixth	December 1, 1959
	2-20997	2(b)-7		Seventh	February 1, 1963
	2-77857	4(b)-8		Eighth	January 1, 1966
	2-25805	2(b)-9		Ninth	February 1, 1967
	2-37161	2(c)		Tenth	June 1, 1970
	2-42043	2(c)		Eleventh	November 1, 1971
	2-45403	2(c)		Twelfth	September 1, 1972
	2-52708	2(c)		Thirteenth	March 1, 1975
	2-77857	4(b)-14		Fourteenth	May 1, 1977
	2-71621	4(c)		Fifteenth	June 1, 1981
	2-77857	4(b)-16		Sixteenth	November 1, 1981
	2-77857	4(c)		Seventeenth	July 1, 1982
	2-81476	4(b)-18		Eighteenth	November 1, 1982
	2-81476	4(c)		Nineteenth	February 1, 1983
	2-90185	4(c)-1		Twentieth	June 1, 1983
	2-90185	4(c)-2		Twenty-first	January 1, 1984
	2-90185	4(c)-3		Twenty-second	April 1, 1984
	2-92738	4(b)-1		Twenty-third	September 1, 1984
	2-99940	4(b)-1		Twenty-fourth	September 1, 1985
	33-11376	4(b)-1		Twenty-fifth	October 1, 1986
	33-14584	4(b)-1		Twenty-sixth	March 1, 1987
	33-24089	4(b)-1		Twenty-seventh	July 1, 1987

Item 14. EXHIBITS, FINANCIAL STATEMENT SCHEDULES AND REPORTS ON FORM 8-K (Continued).

	Previously Filed*			
Exhibits	With File Number	As Exhibit	Number	Dated
	33-30141	4(b)-1	Twenty-eighth	January 1, 1989
	33-35614	4(b)-1	Twenty-ninth	November 1, 1989
4(b)-2			Thirtieth	February 1, 1992
4(c)	2-5609	7(b)	— Mortgage and Deed of Trust, dated as of March 1, 1945, between Texas Electric Service Company and The Fort Worth National Bank, Trustee (Team Bank, successor Trustee).	
4(c)-1			— Supplemental Indentures to Mortgage and Deed of Trust:	
	2-7186	7(b)	First	October 1, 1947
	2-7423	7(c)	Second	April 1, 1948
	2-7894	7(d)	Third	April 1, 1949
	2-8982	7(e)	Fourth	June 1, 1951
	2-9547	4(c)	Fifth	May 1, 1952
	2-10118	4(c)	Sixth	April 1, 1953
	2-12227	2(c)	Seventh	March 1, 1955
	2-60449	2(b)-1	Eighth	March 1, 1956
	2-60449	2(b)-1	Ninth	July 1, 1957
	2-60449	2(b)-1	Tenth	November 1, 1958
	2-21105	2(b)	Eleventh	April 1, 1963
	2-23056	2(b)	Twelfth	February 1, 1965
	2-24384	2(c)	Thirteenth	February 1, 1966
	2-26297	2(c)	Fourteenth	May 1, 1967
	2-31474	2(c)	Fifteenth	March 1, 1969
	2-38358	2(c)	Sixteenth	October 1, 1970
	2-39627	2(c)	Seventeenth	April 1, 1971
	2-42552	2(c)	Eighteenth	January 1, 1972
	2-60449	2(b)-1	Nineteenth	April 1, 1974
	2-60449	2(b)-1	Twentieth	December 1, 1974
	2-60449	2(b)-1	Twenty-first	June 1, 1975
	2-60449	2(b)-1	Twenty-second	March 1, 1976
	2-63425	2(c)	Twenty-third	February 1, 1979
	2-66633	2(c)	Twenty-fourth	March 1, 1980
	2-74809	4(c)-1	Twenty-fifth	November 1, 1981
	2-74809	4(d)-1	Twenty-sixth	December 1, 1981
	2-76675	4(c)	Twenty-seventh	April 1, 1982
	2-80329	4(c)	Twenty-eighth	November 1, 1982
	2-80329	4(d)	Twenty-ninth	December 1, 1982
	2-90185	4(d)-1	Thirtieth	June 1, 1983
	2-90185	4(d)-2	Thirty-first	January 1, 1984
	2-90185	4(d)-3	Thirty-second	April 1, 1984
	2-92738	4(c)-1	Thirty-third	September 1, 1984
	2-99940	4(c)-1	Thirty-fourth	August 1, 1985
	33-9583	4(c)-1	Thirty-fifth	March 1, 1986

Item 14. EXHIBITS, FINANCIAL STATEMENT SCHEDULES AND REPORTS ON FORM 8-K (Continued).

Exhibits	Previously Filed* With File Number	Previously Filed* As Exhibit		Number	Dated
	33-11376	4(c)-1		Thirty-sixth	December 1, 1986
	33-14584	4(c)-1		Thirty-seventh	February 1, 1987
	33-24089	4(c)-1		Thirty-eighth	September 1, 1987
	33-24089	4(c)-2		Thirty-ninth	October 1, 1987
	33-24089	4(c)-3		Fortieth	March 1, 1988
	33-30141	4(c)-1		Forty-first	September 1, 1988
	33-39493	4(c)-1		Forty-second	September 1, 1990
	33-39493	4(c)-2		Forty-third	March 1, 1991
4(c)-2				Forty-fourth	February 1, 1992
4(d)	2-5718	7(c)	—	Mortgage and Deed of Trust, dated as of May 1, 1945, between Texas Power & Light Company and Republic National Bank of Dallas, Trustee (NationsBank of Texas, N.A., successor Trustee).	
4(d)-1			—	Supplemental Indentures to Mortgage and Deed of Trust:	
	2-7204	7(a)		First	October 1, 1947
	2-7446	7(a)		Second	April 1, 1948
	2-9474	4(c)		Third	April 1, 1952
	2-10204	4(c)		Fourth	May 1, 1953
	2-11162	2(b)		Fifth	October 1, 1954
	2-12856	4(c)		Sixth	November 1, 1956
	2-14553	2(b)		Seventh	December 1, 1958
	2-19452	2(b)-1		Eighth	January 1, 1961
	2-21028	2(b)		Ninth	February 1, 1963
	2-24326	2(c)		Tenth	January 1, 1965
	2-24326	2(d)		Eleventh	February 1, 1966
	2-25885	2(c)		Twelfth	February 1, 1967
	2-27853	2(c)		Thirteenth	January 1, 1968
	2-35941	2(c)		Fourteenth	February 1, 1970
	2-38171	2(c)		Fifteenth	September 1, 1970
	2-39083	2(c)		Sixteenth	February 1, 1971
	2-42763	2(c)		Seventeenth	February 1, 1972
	2-46740	2(c)		Eighteenth	February 1, 1973
	2-73790	4(b)-19		Nineteenth	February 1, 1974
	2-73790	4(b)-20		Twentieth	October 1, 1974
	2-52865	2(c)		Twenty-first	April 1, 1975
	2-55210	2(c)		Twenty-second	January 1, 1976
	2-5[illegible]63	2(c)		Twenty-third	February 1, 1977
	2-63369	2(c)		Twenty-fourth	February 1, 1979
	2-67594	(b)(2)-2		Twenty-fifth	May 1, 1980
	2-73790	4(c)		Twenty-sixth	September 1, 1981
	2-77733	4(b)		Twenty-seventh	November 1, 1981
	2-77733	4(c)		Twenty-eighth	June 1, 1982
	2-90185	4(e)-1		Twenty-ninth	November 1, 1982

Item 14. EXHIBITS, FINANCIAL STATEMENT SCHEDULES AND REPORTS ON FORM 8-K (Continued).

Exhibits	Previously Filed* With File Number	As Exhibit	Number	Dated
	2-90185	4(e)-2	Thirtieth	June 1, 1983
	2-90185	4(e)-3	Thirty-first	October 1, 1983
	2-90185	4(e)-4	Thirty-second	January 1, 1984
	2-90185	4(e)-5	Thirty-third	April 1, 1984
	2-92738	4(d)-1	Thirty-fourth	September 1, 1984
	2-97185	4(d)-1	Thirty-fifth	April 1, 1985
	33-01774	4(d)-1	Thirty-sixth	December 1, 1985
	33-9583	4(d)-1	Thirty-seventh	May 1, 1986
	33-11376	4(d)-1	Thirty-eighth	December 1, 1986
	33-14584	4(d)-1	Thirty-ninth	April 1, 1987
	33-24089	4(d)-1	Fortieth	May 1, 1988
	33-30141	4(d)-1	Forty-first	August 1, 1988
	33-35614	4(d)-1	Forty-second	August 1, 1989
	33-35614	4(d)-2	Forty-third	December 1, 1989
	33-35614	4(d)-3	Forty-fourth	February 1, 1990
	33-39493	4(d)-1	Forty-fifth	October 1, 1990
	33-45104	4(d)-1	Forty-sixth	May 1, 1991
	33-45104	4(d)-2	Forty-seventh	July 1, 1991
4(d)-2			Forty-eighth	February 1, 1992
4(e)	2-28016	2(b)-13	— Debenture Agreement, dated as of February 1, 1968, between Dallas Power & Light Company and Morgan Guaranty Trust Company of New York, Trustee.	
4(e)-1	0-11442 Form 10-K (1983)	4(c)-3	— First Supplemental Agreement, dated as of June 21, 1983, to the Debenture Agreement dated as of February 1, 1968, between Dallas Power & Light Company and Morgan Guaranty Trust Company of New York, Trustee.	
4(e)-2	0-11442 10-K (1983)	4(c)-4	— Second Supplemental Agreement, dated as of Form January 1, 1984, to the Deberture Agreement dated as of February 1, 1968, between TU Electric and Morgan Guaranty Trust Company of New York, Trustee.	
4(f)	2-27908	2(d)	— Debenture Agreement, dated as of February 1, 1968, between Texas Electric Service Company and The First National Bank of Fort Worth, Trustee (Team Bank, successor Trustee).	
4(f)-1	0-11442 Form 10-K (1983)	4(d)-3	— First Supplemental Agreement, dated as of June 29, 1983, to the Debenture Agreement dated as of February 1, 1968, between Texas Electric Service Company and The First National Bank of Fort Worth, Trustee (Team Bank, successor Trustee).	

Item 14. EXHIBITS, FINANCIAL STATEMENT SCHEDULES AND REPORTS ON FORM 8-K (Concluded).

Exhibits	Previously Filed* With File Number	Previously Filed* As Exhibit		Number Dated
4(f)-2	0-11442 Form 10-K (1983)	4(d)-4	—	Second Supplemental Agreement, dated as of January 1, 1984, to the Debenture Agreement dated as of February 1, 1968, between TU Electric and InterFirst Bank Fort Worth, N.A., Trustee (Team Bank, successor Trustee).
4(g)	2-31966	4(c)	—	Debenture Agreement, dated as of April 1, 1969, between Texas Power & Light Company and First National Bank of Dallas, Trustee (NationsBank of Texas, N.A., successor Trustee).
4(g)-1	0-11442 Form 10-K (1983)	4(e)-5	—	First Supplemental Agreement, dated as of June 28, 1983, to the Debenture Agreement dated as of April 1, 1969, between Texas Power & Light Company and InterFirst Bank Dallas, National Association, Trustee (NationsBank of Texas, N.A., successor Trustee).
4(g)-2	0-11442 Form 10-K (1983)	4(e)-6	—	Second Supplemental Agreement, dated as of January 1, 1984, to the Debenture Agreement dated April 1, 1969, between TU Electric and InterFirst Bank Dallas, National Association, Trustee (NationsBank of Texas, N.A., successor Trustee).
4(h)			—	Agreement to furnish certain debt instruments.
12			—	Computation of Ratio of Earnings to Fixed Charges.
24(a)			—	Consent of Counsel.
24(b)			—	Independent Auditors' Consent.
28(a)	0-11442 Form 10-K (1987)	28(b)	—	Agreement, dated as of February 12, 1988, between TU Electric and Texas Municipal Power Agency.
28(b)	0-11442 Form 10-Q (Quarter Ended June 30, 1988)	28(c)	—	Agreement, dated as of July 5, 1988, between the Company and the Brazos Electric Power Cooperative, Inc.
28(c)	0-11442 Form 10-K (1989)	28(d)	—	Agreement, dated as of February 1, 1990, between TU Electric and Tex-La Electric Cooperative, Inc.
28(d)	0-11442 Form 10-K (1990)		—	Amended and Restated Credit Agreement, dated as of April 1, 1990, among the Company, Texas Utilities, certain banks and Morgan Guaranty Trust Company of New York, Agent.

*Incorporated herein by reference.

TEXAS UTILITIES ELECTRIC COMPANY

SCHEDULE V — ELECTRIC PLANT

For Each of the Three Years in the Period Ended December 31, 1991

COLUMN A	COLUMN B	COLUMN C	COLUMN D	COLUMN E	COLUMN F
Classification	Balance at Beginning of Year	Additions at Cost	Retirements	Other Changes — Add	Balance at End of Year
			Thousands of Dollars		
Year Ended December 31, 1991					
Electric plant					
In service:					
Production	$10,342,116	$ 90,446	$11,175	$ —	$10,421,387
Transmission	1,388,959	57,829	3,223	—	1,443,565
Distribution	3,190,258	220,796	33,658	—	3,377,396
General	408,294	26,419	9,265	—	425,448
Total	15,329,627	395,490	57,321	—	15,667,796
Construction work in progress	4,012,241	796,847	—	—	4,809,088
Nuclear fuel — net	311,416	47,678	—	(25,395)	333,701
Held for future use	28,989	80	—	—	29,069
Electric plant before reserve	19,682,273	1,240,095	57,321	(25,393)	20,839,654
Less reserve for regulatory disallowances	—	—	—	(1,308,460)(a)	(1,308,460)
Total electric plant	$19,682,273	$1,240,095	$57,321	$(1,333,853)	$19,531,194
Year Ended December 31, 1990					
Electric plant					
In service:					
Production	$ 3,121,363	$ 7,237,355	$16,602	$ —	$10,342,116
Transmission	1,321,739	68,528	2,852	1,544 (b)	1,388,959
Distribution	3,040,114	185,134	34,990	—	3,190,258
General	390,718	24,235	6,659	—	408,294
Total	7,873,934	7,515,252	61,103	1,544	15,329,627
Construction work in progress	9,915,896	(6,085,612)	—	181,957 (b)	4,012,241
Nuclear fuel — net	301,676	7,338	—	2,402 (b)(c)	311,416
Held for future use	25,252	3,737	—	—	28,989
Total electric plant	$18,116,758	$ 1,440,715	$61,103	$ 185,903	$19,682,273
Year Ended December 31, 1989					
Electric plant					
In service:					
Production	$ 3,069,851	$ 54,145	$ 2,633	$ —	$ 3,121,363
Transmission	1,277,098	48,472	3,831	—	1,321,739
Distribution	2,882,086	187,369	29,341	—	3,040,114
General	381,414	15,867	6,563	—	390,718
Total	7,610,449	305,853	42,368	—	7,873,934
Construction work in progress	8,433,261	1,482,635	—	—	9,915,896
Nuclear fuel	303,282	(1,606)	—	—	301,676
Held for future use	23,684	1,568	—	—	25,252
Total electric plant	$16,370,676	$1,788,450	$42,368	$ —	$18,116,758

(a) Disallowed Comanche Peak related costs. (See Note 12 to Financial Statements.)

(b) Purchase of minority ownership interest in Comanche Peak. (See Note 1 to Financial Statements.)

(c) Other changes to nuclear fuel include $13,709,000 added upon purchase from Tex-La and $11,307,000 deducted for amortization.

TEXAS UTILITIES ELECTRIC COMPANY

SCHEDULE VI — ACCUMULATED DEPRECIATION

For Each of the Three Years in the Period Ended December 31, 1991

COLUMN A	COLUMN B	COLUMN C	COLUMN D	COLUMN E	COLUMN F
Classification	Balance at Beginning of Year	Additions Charged to Costs and Expenses (a)	Net Retirements	Other Changes — Add (b)	Balance at End of Year
			Thousands of Dollars		
Year Ended December 31, 1991					
Accumulated depreciation	$3,026,995	$418,899	$60,582	$7,151	$3,392,463
Year Ended December 31, 1990					
Accumulated depreciation	$2,762,101	$314,044	$57,606	$8,456	$3,026,995
Year Ended December 31, 1989					
Accumulated depreciation	$2,558,282	$240,466	$46,203	$9,556	$2,762,101

(a) Includes depreciation on lignite fuel production facilities charged to fuel and beginning in 1990 decommissioning expense for Comanche Peak.

(b) Depreciation and depletion charged to various accounts, including depreciation of transportation and work equipment, based on estimated lives thereof, are charged to clearing accounts and allocated on the basis of the use of such equipment.

TEXAS UTILITIES ELECTRIC COMPANY

SCHEDULE VIII — VALUATION AND QUALIFYING ACCOUNTS

For Each of the Three Years in the Period Ended December 31, 1991

COLUMN A	COLUMN B	COLUMN C		COLUMN D	COLUMN E
		Additions			
Classification	Balance at Beginning of Year	Charged to Costs and Expenses	Charged to Other Accounts	Deductions (a)	Balance at End of Year
		Thousands of Dollars			
Valuation account, deducted from related asset on the balance sheet —					
Year ended December 31, 1991					
Reserve for regulatory disallowances	$ —	$1,381,145	$ —	$ —	$1,381,145
Allowance for uncollectible accounts	2,290	14,226	—	13,585	2,931
Year ended December 31, 1990					
Allowance for uncollectible accounts	$ 3,141	$13,670	$ —	$14,521	$ 2,290
Year Ended December 31, 1989					
Allowance for uncollectible accounts	$13,012	$14,546	$ —	$24,417	$ 3,141

(a) Deductions from the allowance represent uncollectible accounts written off, less recoveries of amounts previously written off. Included in 1989 is $7,087,000 of allowance for uncollectible accounts associated with the sales of accounts receivable.

TEXAS UTILITIES ELECTRIC COMPANY

SCHEDULE IX — SHORT-TERM BORROWINGS

For Each of the Three Years in the Period Ended December 31, 1991

COLUMN A	COLUMN B	COLUMN C	COLUMN D	COLUMN E	COLUMN F
Category of Aggregate Short-term Borrowings	Balance At End of Year	Weighted Average Interest Rate	Maximum Amount Outstanding During Year	Weighted Average Amount Outstanding During Year (a)	Weighted Average Interest Rate During Year (a)
			Thousands of Dollars		
Year Ended December 31, 1991					
Amounts payable to banks for borrowings	$250,000	5.77%	$300,000	$229,681	6.51%
Holders of commercial paper	—	—	133,800	35,756	6.84
Year Ended December 31, 1990					
Amounts payable to banks for borrowings (b)	$ 35,000	10.00%	$ 35,000	$ 97	9.86%
Holders of commercial paper	—	—	305,235	86,914	8.53
Year Ended December 31, 1989	$ —	— %	$ —	$ —	— %

(a) Weighted averages are based upon daily amounts outstanding and equivalent annual interest thereon.
(b) Bank loan is at a rate at all times equal to the prime commercial lending rate; such loan was repaid on January 2, 1991.

TEXAS UTILITIES ELECTRIC COMPANY

SCHEDULE X — SUPPLEMENTARY INFORMATION

For Each of the Three Years in the Period Ended December 31, 1991

COLUMN A	COLUMN B		
	Charged to Expenses and Other Accounts		
	Year Ended December 31,		
Item	1991	1990	1989
	Thousands of Dollars		
Taxes other than income:			
Ad valorem	$176,414	$113,320	$102,872
Local gross receipts	122,683	112,787	109,217
State gross receipts	71,512	64,570	61,841
State franchise	49,182	31,481	14,261
Social security and unemployment	38,170	36,938	36,083
Public Utility Commission assessment	7,664	7,011	6,753
Miscellaneous	18,821	16,146	15,760
Total	$484,446	$382,253	$346,787
Charged to:			
Operating expenses	$437,347	$336,323	$299,588
Electric plant and sundry accounts	47,099	43,930	47,199

Maintenance and repairs, depletion, amortization, royalties, research and development, and advertising, other than amounts set out separately in the financial statements, are not material.

SIGNATURES

Pursuant to the requirements of Section 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.

TEXAS UTILITIES ELECTRIC COMPANY

Date: March 13, 1992

By: /s/ ERLE NYE

(Erle Nye, Chairman of the Board and Chief Executive)

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 date indicated.

Signature	Title	Date
/s/ ERLE NYE (Erle Nye, Chairman of the Board and Chief Executive)	Principal Executive Officer and Director	
/s/ H. JARRELL GIBBS (H. Jarrell Gibbs, Executive Vice President)	Principal Financial Officer and Director	
/s/ S. S. SWIGER (S.S. Swiger, Senior Vice President and Controller)	Principal Accounting Officer	
/s/ T. L. BAKER (T. L. Baker)	Director	
/s/ TOM BLAKEY (Tom Blakey)	Director	March 13, 1992
/s/ J. S. FARRINGTON (J.S. Farrington)	Director	
/s/ MICHAEL D. SPENCE (Michael D. Spence)	Director	
/s/ W. M. TAYLOR (W. M. Taylor)	Director	
/s/ E. L. WATSON (E. L. Watson)	Director	