ENTERGY

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Grand Gulf Nuclear Station

August 2, 1995

Nuclear Regulatory Commission
Document Control Desk
Washington, D.C. 20555

Subject: Grand Gulf Nuclear Station
Docket No. 50-416
License No. NPF-29
1994 Financial Reports

GNRO-95/00089

Gentlemen:

The 1994 Annual Financial Reports for System Energy Resources, Inc., South Mississippi Electric Power Association, Mississippi Power and Light Co., and Entergy Operations, Inc., licensees of Grand Gulf Nuclear Station, are herein submitted in response to the requirement of 10CFR50.71(b).

Yours truly,

CRH/MTC/

attachments:
1. Combined 1994 Annual Reports for System Energy Resources, Inc., Mississippi Power and Light Co., and Entergy Operations, Inc.
2. 1994 South Mississippi Electric Power Association Annual Report

cc: (See Next Page)

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SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

(Mark One)

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

For the Fiscal Year Ended December 31, 1994

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

For the transition period from _____ to _____

Commission File Number	Registrant, State of Incorporation, Address of Principal Executive Offices and Telephone Number	IRS Employer Identification No.
1-11299	ENTERGY CORPORATION (a Delaware corporation) 639 Loyola Avenue New Orleans, Louisiana 70113 Telephone (504) 529-5262	13-5550175
1-10764	ARKANSAS POWER & LIGHT COMPANY (an Arkansas corporation) 425 West Capitol Avenue, 40th Floor Little Rock, Arkansas 72201 Telephone (501) 377-4000	71-0005900
1-2703	GULF STATES UTILITIES COMPANY (a Texas corporation) 350 Pine Street Beaumont, Texas 77701 Telephone (409) 838-6631	74-0662730
1-8474	LOUISIANA POWER & LIGHT COMPANY (a Louisiana corporation) 639 Loyola Avenue New Orleans, Louisiana 70113 Telephone (504) 529-5262	72-0245590
0-320	MISSISSIPPI POWER & LIGHT COMPANY (a Mississippi corporation) 308 East Pearl Street Jackson, Mississippi 39201 Telephone (601) 969-2311	64-0205830
0-5807	NEW ORLEANS PUBLIC SERVICE INC. (a Louisiana corporation) 639 Loyola Avenue New Orleans, Louisiana 70113 Telephone (504) 529-5262	72-0273040
1-9067	SYSTEM ENERGY RESOURCES, INC. (an Arkansas corporation) Echelon One 1340 Echelon Parkway Jackson, Mississippi 39213 Telephone (601) 368-5000	72-0752777

TABLE OF CONTENTS

			Page Number
Definitions			i
Part I			
	Item 1.	Business	1
	Item 2.	Properties	53
	Item 3.	Legal Proceedings	53
	Item 4.	Submission of Matters to a Vote of Security Holders	53
Part II			
	Item 5.	Market for Registrants' Common Equity and Related Stockholder Matters	54
	Item 6.	Selected Financial Data	55
	Item 7.	Management's Discussion and Analysis of Financial Condition and Results of Operations	55
	Item 8.	Financial Statements and Supplementary Data	56
	Item 9.	Changes in and Disagreements with Accountants on Accounting and Financial Disclosure	341
Part III			
	Item 10.	Directors and Executive Officers of the Registrants	341
	Item 11.	Executive Compensation	350
	Item 12.	Security Ownership of Certain Beneficial Owners and Management	359
	Item 13.	Certain Relationships and Related Transactions	363
Part IV			
	Item 14.	Exhibits, Financial Statement Schedules, and Reports on Form 8-K	364
Experts			365
Signatures			366
Consents of Experts			373
Report of Independent Accountants on Financial Statement Schedules			380
Independent Auditors' Report on Financial Statement Schedules			381
Index to Financial Statement Schedules			S-1
Exhibit Index			E-1

This combined Form 10-K is separately filed by Entergy Corporation, Arkansas Power & Light Company, Gulf States Utilities Company, Louisiana Power & Light Company, Mississippi Power & Light Company, New Orleans Public Service Inc., and System Energy Resources, Inc. Information contained herein relating to any individual company is filed by such company on its own behalf. Each company makes no representation as to information relating to the other companies.

This report (including the material incorporated herein by reference) must be read in its entirety. No one section of the report deals with all aspects of the subject matter.

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

Registrant	Title of Class	Name of Each Exchange on Which Registered
Entergy Corporation	Common Stock, $0.01 Par Value - 227,410,827 Shares outstanding at February 28, 1995	New York Stock Exchange, Inc. Midwest Stock Exchange Incorporated Pacific Stock Exchange Incorporated
Arkansas Power & Light Company	$2.40 Preferred Stock, Cumulative, $0.01 Par Value ($25 Involuntary Liquidation Value)	New York Stock Exchange, Inc.
Gulf States Utilities Company	Preferred Stock, Cumulative, $100 Par Value:	
	$4.40 Dividend Series	New York Stock Exchange, Inc.
	$4.52 Dividend Series	New York Stock Exchange, Inc.
	$5.08 Dividend Series	New York Stock Exchange, Inc.
	$8.80 Dividend Series	New York Stock Exchange, Inc.
	Adjustable Rate Series B (Depository Receipts)	New York Stock Exchange, Inc.
	Preference Stock, Cumulative, without Par Value $1.75 Dividend Series	New York Stock Exchange, Inc.
Louisiana Power & Light Company	9.68% Preferred Stock, Cumulative, $25 Par Value	New York Stock Exchange, Inc.
	12.64% Preferred Stock, Cumulative, $25 Par Value	New York Stock Exchange, Inc.

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

Registrant	Title of Class
Arkansas Power & Light Company	Preferred Stock, Cumulative, $100 Par Value Preferred Stock, Cumulative, $25 Par Value Preferred Stock, Cumulative, $0.01 Par Value
Louisiana Power & Light Company	Preferred Stock, Cumulative, $100 Par Value Preferred Stock, Cumulative, $25 Par Value
Mississippi Power & Light Company	Preferred Stock, Cumulative, $100 Par Value
New Orleans Public Service Inc	Preferred Stock, Cumulative, $100 Par Value 4 3/4% Preferred Stock, Cumulative, $100 Par Value

Indicate by check mark whether the registrants (1) have 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 registrants were required to file such reports), and (2) have 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 the registrants' 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. [ ]

The aggregate market value of Entergy Corporation Common Stock, $0.01 Par Value, held by non-affiliates, was $5.1 billion based on the reported last sale price of such stock on the New York Stock Exchange on February 28, 1995. Entergy Corporation is the sole holder of the common stock of Arkansas Power & Light Company, Gulf States Utilities Company, Louisiana Power & Light Company, Mississippi Power & Light Company, New Orleans Public Service Inc., and System Energy Resources, Inc.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Proxy Statement of Entergy Corporation to be filed in connection with its Annual Meeting of Stockholders, to be held May 26, 1995, are incorporated by reference into Part III hereof.

DEFINITIONS

Certain abbreviations or acronyms used in the text and notes are defined below:

Abbreviation or Acronym	Term
AFUDC	Allowance for Funds Used During Construction
Algiers	15th Ward of the City of New Orleans, Louisiana
ALJ	Administrative Law Judge
Alliance	Alliance for Affordable Energy, Inc.
ANO	Arkansas Nuclear One Steam Electric Generating Station (nuclear)
ANO 1	Unit No. 1 of ANO
ANO 2	Unit No. 2 of ANO
AP&L	Arkansas Power & Light Company
APSC	Arkansas Public Service Commission
Arkansas District Court	United States District Court for the Western District of Arkansas
Availability Agreement	Agreement, dated as of June 21, 1974, as amended, among System Energy and AP&L, LP&L, MP&L, and NOPSI, and the assignments thereof
Cajun	Cajun Electric Power Cooperative, Inc.
Capital Funds Agreement	Agreement, dated as of June 21, 1974, as amended, between System Energy and Entergy Corporation, and the assignments thereof
CCLM	Customer-Controlled Load Management (a DSM activity utilizing residential time-of-use rates)
City of New Orleans or City	New Orleans, Louisiana
Council	Council of the City of New Orleans, Louisiana
D.C. Circuit	United States Court of Appeals for the District of Columbia Circuit
DOE	United States Department of Energy
DSM	Demand-Side Management (Least Cost Plan activities that influence electricity usage by consumers)
Eighth Circuit	United States Court of Appeals for the Eighth Circuit
EPAct	Energy Policy Act of 1992

Abbreviation or Acronym	Term
Entergy or System	Entergy Corporation and its various direct and indirect subsidiaries
Entergy Corporation	Entergy Corporation, a Delaware corporation, successor to Entergy Corporation, a Florida corporation
Entergy Enterprises	Entergy Enterprises, Inc.
Entergy Operations	Entergy Operations, Inc.
Entergy Power	Entergy Power, Inc.
Entergy Services	Entergy Services, Inc.
EPA	Environmental Protection Agency
EWG	Exempt Wholesale Generator
February 4 Resolution	The Resolution (including the Determinations and Order referred to therein) adopted by the Council on February 4, 1988, disallowing the recovery by NOPSI of $135 million of previously deferred Grand Gulf 1 related costs
FERC	Federal Energy Regulatory Commission
Grand Gulf Station	Grand Gulf Steam Electric Generating Station (nuclear)
Grand Gulf 1	Unit No. 1 of the Grand Gulf Station (nuclear)
Grand Gulf 2	Unit No. 2 of the Grand Gulf Station (nuclear)
GSU	Gulf States Utilities Company (including wholly owned subsidiaries - Varibus Corporation, GSG&T, Inc., Prudential Oil & Gas, Inc., and Southern Gulf Railway Company)
Holding Company Act	Public Utility Holding Company Act of 1935, as amended
Independence Station	Independence Steam Electric Generating Station (coal)
Independence 2	Unit No. 2 of the Independence Station
IRS	Internal Revenue Service
KV	Kilovolts
KWH	Kilowatt-Hour(s)

Abbreviation or Acronym	Term
Least Cost Plan	Least Cost Integrated Resource Plan (combination of demand- and supply-side resources to be used by Entergy to satisfy electricity demand)
LP&L	Louisiana Power & Light Company
LPSC	Louisiana Public Service Commission
MCF	1,000 cubic feet of gas
Merger	The combination transaction, consummated on December 31, 1993, by which GSU became a subsidiary of Entergy Corporation and Entergy Corporation became a Delaware corporation
MP&L	Mississippi Power & Light Company
MPSC	Mississippi Public Service Commission
MW	Megawatt(s)
Nelson Unit 6	Unit No. 6 (coal) of the Nelson Steam Electric Generating Station
NISCO	Nelson Industrial Steam Company
1986 NOPSI Settlement	Settlement, effective March 25, 1986, between NOPSI and the Council regarding NOPSI's Grand Gulf-related rate issues
1991 NOPSI Settlement	Settlement, retroactive to October 4, 1991, among NOPSI, the Council, and the Alliance that settled certain Grand Gulf 1 prudence issues and certain litigation related to the February 4 Resolution
NOPSI	New Orleans Public Service Inc.
NRC	Nuclear Regulatory Commission
PRP	Potentially Responsible Party (a person or entity that may be responsible for remediation of environmental contamination)
PUCT	Public Utility Commission of Texas
PURPA	Public Utility Regulatory Policies Act

Abbreviation or Acronym	Term
Rate Cap	The level of GSU's retail electric base rates in effect at December 31, 1993, for the Louisiana retail jurisdiction, and the level in effect prior to the Texas Cities Rate Settlement for the Texas retail jurisdiction, that may not be exceeded for the five years following December 31, 1993
Reallocation Agreement	1981 Agreement, superseded in part by a June 13, 1985 decision of FERC, among AP&L, LP&L, MP&L, NOPSI, and System Energy relating to the sale of capacity and energy from the Grand Gulf Station
Ritchie 2	Unit No. 2 of the R. E. Ritchie Steam Electric Generating Station (gas/oil)
River Bend	River Bend Steam Electric Generating Station (nuclear), owned 70% by GSU.
RUS	Rural Utility Services (formerly the Rural Electrification Administration or "REA")
SEC	Securities and Exchange Commission
SFAS	Statement of Financial Accounting Standards, promulgated by the Financial Accounting Standards Board
SRG&T	Sam Rayburn G&T, Inc.
SRMPA	Sam Rayburn Municipal Power Agency
System Agreement	Agreement, effective January 1, 1983, as modified, among the System operating companies relating to the sharing of generating capacity and other power resources
System Energy	System Energy Resources, Inc.
System Fuels	System Fuels, Inc.
System operating companies	AP&L, GSU, LP&L, MP&L, and NOPSI, collectively
Unit Power Sales Agreement	Agreement, dated as of June 10, 1982, as amended and approved by FERC, among AP&L, LP&L, MP&L, NOPSI, and System Energy, relating to the sale of capacity and energy from System Energy's share of Grand Gulf 1
Waterford 3	Unit No. 3 (nuclear) of the Waterford Steam Electric Generating Station

PART I

Item 1. Business

BUSINESS OF ENTERGY

General

Entergy Corporation was originally incorporated under the laws of the State of Florida on May 27, 1949. On December 31, 1993, Entergy Corporation merged with and into Entergy-GSU Holdings, Inc., a Delaware corporation, which then changed its name to Entergy Corporation. Entergy Corporation is a holding company registered under the Holding Company Act and does not own or operate any significant physical properties. Entergy Corporation owns all of the outstanding common stock of five retail operating electric utility subsidiaries, AP&L, GSU, LP&L, MP&L, and NOPSI. AP&L was incorporated under the laws of the State of Arkansas in 1926; GSU was incorporated under the laws of the State of Texas in 1925; LP&L and NOPSI were incorporated under the laws of the State of Louisiana in 1974 and 1926, respectively; and MP&L was incorporated under the laws of the State of Mississippi in 1963. As of December 31, 1994, these operating companies provided electric service to approximately 2.4 million customers in the States of Arkansas, Louisiana, Mississippi, Tennessee and Texas. In addition, GSU furnished gas service in the Baton Rouge, Louisiana area, and NOPSI furnished gas service in the New Orleans, Louisiana area. GSU produces and sells, on an unregulated basis, process steam and by-product electricity supplied from its steam electric extraction plant to a large industrial customer. The business of the System is subject to seasonal fluctuations with the peak period occurring during the third quarter. During 1994, the System's electricity sales as a percentage of total System energy sales were: residential - 26.9%; commercial - 20.6%; and industrial - 42.1%. Electric revenues from these sectors as a percentage of total System electric revenues were: 36.3% - residential; 25.6% - commercial; and 31.3% - industrial. Sales to governmental and municipal sectors and to nonaffiliated utilities accounted for the balance of energy sales. The System's major industrial customers are in the chemical processing, petroleum refining, paper products, and food products industries.

Entergy Corporation also owns all of the outstanding common stock of System Energy, Entergy Services, Entergy Operations, Entergy Power, and Entergy Enterprises. System Energy is a nuclear generating company that was incorporated under the laws of the State of Arkansas in 1974. System Energy sells the capacity and energy at wholesale from its 90% interest in Grand Gulf 1 to its only customers, AP&L, LP&L, MP&L, and NOPSI (see "Capital Requirements and Future Financing - Certain System Financial and Support Agreements - *Unit Power Sales Agreement*," below). System Energy has approximately a 78.5% ownership interest and an 11.5% leasehold interest in Grand Gulf 1. Entergy Services, a Delaware corporation, provides general executive, advisory, administrative, accounting, legal, engineering, and other services to the System companies, generally at cost. Entergy Operations, a Delaware corporation, is a nuclear management company that operates ANO, River Bend, Waterford 3, and Grand Gulf 1, subject to the owner oversight of AP&L, GSU, LP&L, and System Energy, respectively. Entergy Power, a Delaware corporation, is an independent power producer that owns 809 MW of generating capacity and markets its capacity and energy in the wholesale market outside Arkansas and Missouri and in markets not otherwise presently served by the System. (For further information on regulatory proceedings related to Entergy Power, see "Rate Matters and Regulation - Rate Matters - Wholesale Rate Matters - *Entergy Power*," below). Entergy Enterprises is a nonutility company incorporated under Delaware law that investigates and develops energy-related projects and other businesses whose products and activities are or may be of benefit to the System's utility business (see "Corporate Development," below). Entergy Enterprises also markets outside the System technical expertise, products, and services developed by the System companies that have commercial value beyond their use in the System's operations and provides services to certain nonutility companies in the System. Entergy Corporation has formed subsidiaries to participate in utility projects located outside the System's retail service territory, both domestically and in foreign countries (see "Corporate Development," below).

AP&L, LP&L, MP&L, and NOPSI own 35%, 33%, 19%, and 13%, respectively, of all the common stock of System Fuels, a non-profit subsidiary incorporated in Louisiana that implements and/or maintains certain programs to procure, deliver, and store fuel supplies for the System.

GSU has four wholly-owned subsidiaries: Varibus Corporation, GSG&T, Inc., Southern Gulf Railway Company, and Prudential Oil & Gas, Inc. Varibus Corporation operates intrastate gas pipelines in Louisiana, which are used primarily to transport fuel to two of GSU's generating stations. GSG&T, Inc. owns the Lewis Creek Station, a gas-fired generating plant, which is leased to and operated by GSU. Southern Gulf Railway Company owns and will operate several miles of rail track being constructed in Louisiana for the purpose of transporting coal for use as a boiler fuel at Nelson Unit 6. Prudential Oil & Gas, Inc., which was formerly in the business of exploring, developing, and operating oil and gas properties in Texas and Louisiana, is presently inactive.

Entergy Corporation-GSU Merger

On December 31, 1993, GSU became a wholly-owned subsidiary of Entergy Corporation. As consideration to GSU's shareholders, Entergy Corporation paid $250 million in cash and issued 56,695,724 shares of its common stock, based upon a valuation of $35.8417 per share, in exchange for outstanding shares of GSU common stock. See "Rate Matters and Regulation - Regulation - Other Regulation and Litigation," for information on requests for rehearing and appeals of certain regulatory approvals of the Merger.

Unless otherwise noted, consolidated financial and statistical information contained in this report for the years ended December 31, 1994 and 1993 (such as assets, liabilities, and property) includes the associated GSU amounts. Consolidated financial and statistical information (such as revenues, sales, and expenses) for the year ended December 31, 1994 includes such GSU amounts, while periods ending before January 1, 1994 do not include GSU amounts; those amounts are presented separately for GSU herein.

Certain Industry and System Challenges

The System's business is affected by various challenges and issues including those that confront the electric utility industry in general. These issues and challenges include:

- an increasingly competitive environment (see "Competition," below);
- adaptation to structural changes in the electric utility industry and changes in the regulation of generation and transmission of electricity (see "Competition - *General*" below);
- continued cost management (particularly in the area of operation and maintenance costs at nuclear units) to improve financial results and to minimize or eliminate the need for rate increase requests and, to the extent possible, accommodate rate reductions while maintaining profitability (see "Rate Matters and Regulation - Rate Matters - Retail Rate Matters," below);
- achieving cost savings anticipated with the Merger;
- compliance with regulatory requirements with respect to nuclear operations (see "Rate Matters and Regulation - Regulation - Regulation of the Nuclear Power Industry," below) and environmental matters (see "Rate Matters and Regulation - Regulation - Environmental Regulation," below);
- achieving enhanced earnings despite lower authorized returns and slow growth in the domestic utility business (see "Corporate Development," below);
- resolving GSU's major contingencies, including potential write-offs and refunds related to River Bend (see "Rate Matters and Regulation - Rate Matters - Retail Rate Matters - *GSU*," below).

litigation with Cajun relating to its ownership interest in River Bend, and Cajun's bankruptcy proceedings (see "Rate Matters and Regulation - Regulation - Other Regulation and Litigation - *GSU*," below), and

- the implementation of a proposed accounting standard that describes the circumstances in which assets are determined to be impaired, which may eventually be applied to stranded investments as discussed below. (see Entergy Corporation and Subsidiaries' "Management's Financial Discussion and Analysis - Significant Factors and Known Trends").

Corporate Development

Entergy Corporation continues to consider opportunities to expand its utility and utility related businesses that are not regulated by state and local regulatory authorities (nonregulated businesses). Entergy Corporation's investment strategy is to invest in nonregulated business opportunities that have the potential to earn a greater rate of return than its regulated utility operations, and Entergy Corporation may invest up to approximately $150 million per year for the next several years in nonregulated businesses. Entergy Corporation's nonregulated businesses currently fall into two broad categories: power development and new technology related to the utility business. Entergy Corporation made investments in Argentina's and Pakistan's electric energy infrastructure, as described below, and is pursuing additional projects in North America, Central America, South America, Europe, and Asia. Entergy Corporation opened an office in Hong Kong in 1994 and expects to open offices in South America and Europe in 1995. Entergy Corporation is negotiating in China to participate in two power generation projects, Datong and Taishan, which are expected to receive final approval in 1995 or 1996. The Datong and Taishan projects involve the expansion of an existing coal-fired plant and construction of additional coal-fired plants. To date, Entergy Corporation has made no investment in these projects; however, Entergy Corporation's share of these pro[illegible]s may total approximately $115 million. In addition, Entergy Corporation is exploring the possibility to provide telecommunications services that allow customers to control energy usage.

Current investments in nonregulated businesses include the following:

(1) In 1990, Entergy Power purchased from AP&L 100% of Ritchie 2 and 31 1/2% of Independence 2. Entergy Power is currently selling capacity and energy from both plants. Entergy Corporation originally financed Entergy Power principally with a note between itself and Entergy Power. This note is scheduled to expire on June 30, 1995. As of December 31, 1994, this note amounted to $221.5 million. In 1994, Entergy Power requested, but has not yet received, authorization from the SEC to convert amounts outstanding under the note plus accrued interest to a capital contribution.

(2) Entergy Corporation's subsidiary, Entergy Power Development Corporation an EWG under the provisions of the EPAct, through its subsidiary, Entergy Richmond Power Corporation (which is also an EWG), owns a 50% interest in an independent power plant in Richmond, Virginia. The power plant is jointly-owned and operated by the Enron Power Corporation (Enron), a developer of independent power projects. The plant has a 25-year contract to sell electricity to Virginia Electric & Power Company (VEPCO). Entergy Corporation's investment in the project totals approximately $13.5 million. Entergy Corporation has been notified by Enron that, prior to 1994, the facility did not met the FERC efficiency test to maintain qualifying facility status as required by the contract with VEPCO. Enron has indicated that the facility has met the test in 1994. The failure to meet the test prior to 1994 could result in a default under the VEPCO contract. However, Entergy Richmond Power Corporation, Enron, and VEPCO are currently involved in negotiations to amend the contract to resolve this issue.

(3) Entergy Enterprises has a 7.9% equity interest in First Pacific Networks, Inc. (FPN), a communications company, and has a license from FPN in connection with utility applications being jointly developed by Entergy Enterprises and FPN, for FPN's patented communications technology. Entergy Enterprises' investment in FPN is approximately $11.8 million, of which $9.5 million is equity investment.

(4) Entergy Enterprises' subsidiary, Entergy Systems and Service, Inc. (Entergy SASI), holds a 9.95% equity interest in Systems and Service International, Inc. (SASI), a manufacturer of efficient lighting products. Entergy SASI distributes such products in conjunction with providing various energy management services to its customers. Entergy SASI also made a loan to SASI, acquired the business and assets of SASI's distribution subsidiary, and entered into an agreement to distribute SASI's products. Entergy Enterprises' investment in Entergy SASI is approximately $13.5 million of which $2.3 million is invested in SASI common stock. Entergy Corporation has provided to Entergy SASI $72.3 million in loans, as of December 31, 1994, to fund Entergy SASI's installment sale agreements with its customers.

(5) Entergy Corporation's subsidiary, Entergy, S.A., participated in a consortium with other nonaffiliated companies that acquired a 60% interest in Argentina's Costanera steam electric generating facility consisting of seven natural gas- and oil-fired generating units, with a total installed capacity of 1,260 MW. Entergy Corporation's initial investment to acquire its 10% interest in the consortium was approximately $10.5 million and its maximum financial obligation currently authorized by the SEC in connection with this investment is $22.5 million.

(6) Entergy Corporation, through two subsidiaries, Entergy Argentina, S.A., and Entergy Argentina, S.A. Ltd., participated in a consortium with other nonaffiliated companies that acquired a 51% interest in a foreign electric distribution company providing service to Buenos Aires, Argentina. Entergy Corporation's initial investment to acquire its 10% interest in the consortium was approximately $58.2 million and its maximum financial obligation currently authorized by the SEC in connection with this investment is $77.5 million.

(7) Entergy Corporation, through its subsidiary, Entergy Transener, S.A., participated in a consortium with other nonaffiliated companies that acquired a 65% interest in a foreign transmission system providing service in Argentina. Entergy Corporation's initial investment in the project totals approximately $20.5 million. Depending upon the consortium's ability to continue its financing of a portion of its investment in the transmission system, Entergy Corporation could be required in 1995 to increase its investment by approximately $9 million.

(8) In 1994, Entergy Corporation, through a new subsidiary, Entergy Pakistan, Ltd., acquired a 10% interest in the Hub River steam electric generating facility under development in Pakistan. Entergy Corporation's initial investment to acquire its 10% interest in the consortium was $50.2 million.

In 1994, Entergy Corporation's nonregulated investments reduced consolidated net income by approximately $31.7 million. In the near term, these investments are unlikely to have a positive effect on Entergy Corporation's earnings; but management believes that these investments will contribute to future earnings growth. These investments may involve a higher degree of risk than domestic regulated utility enterprises.

International operations are subject to the risks inherent in conducting business abroad, including possible nationalization or expropriation, price and exchange controls, limitations on foreign participation in local governmental enterprises, and other restrictive actions. Changes in the relative value of currencies take place from time to time and their effects may be favorable or unfavorable on results of operations. In addition, there are exchange control restrictions in certain countries relating to repatriation of earnings.

Selected Data

Selected customer and sales data for 1994 are summarized in the following tables:

1994 - Selected Customer Data

	Area Served	Customers as of December 31, 1994 Electric	Gas
AP&L	Portions of Arkansas	599,702	-
GSU	Portions of Texas and Louisiana	595,348	86,416
LP&L	Portions of Louisiana	607,002	-
MP&L	Portions of Mississippi	367,692	-
NOPSI	City of New Orleans, except Algiers, which is provided electric service by LP&L	189,836	153,259
System		2,359,580	239,675

1994 - Selected Electric Energy Sales Data

	AP&L	GSU	LP&L	MP&L	NOPSI	System Energy	Entergy System
				(Millions of KWH)			
Electric Department:							
Sales to retail customers	15,841	28,763	29,064	10,480	5,396	-	89,544
Sales for resale:							
- Affiliates	10,428	2,676	10	1,079	92	8,653	-
- Others	5,069	840	776	512	202	-	7,908
Total	31,338	32,279	29,850	12,071	5,690	8,653	97,452
Steam Department:							
- Sales to steam products customer	-	1,659	-	-	-	-	1,659
TOTAL	31,338	33,938	29,850	12,071	5,690	8,653	99,111
Average use per residential customer (KWH)	10,743	14,220	13,945	12,777	11,076	-	12,793

NOPSI sold 16,982,648 MCF of natural gas to retail customers in 1994. Revenues from natural gas operations for each of the three years in the period ended December 31, 1994 were material for NOPSI, but not material for the System (see "Industry Segments" below for a description of NOPSI's business segments).

GSU sold 6,967,018 MCF of natural gas to retail customers in 1994. Revenues from natural gas operations for each of the three years in the period ended December 31, 1994 were not material for GSU.

See "Entergy Corporation and Subsidiaries Selected Financial Data - Five-Year Comparison," and "Selected Financial Data - Five-Year Comparison of AP&L, GSU, LP&L, MP&L, NOPSI and System Energy," (which follow each company's notes to financial statements herein) for further information with respect to operating statistics.

Employees

As of December 31, 1994, Entergy had 16,037 employees as follows:

Full-time:	
Entergy Corporation	-
AP&L	2,423
GSU	2,656
LP&L	1,539
MP&L	1,186
NOPSI	660
System Energy	-
Entergy Operations	4,313
Entergy Services	2,631
Other Subsidiaries	494
Total Full-time	15,902
Part-time	135
Total Entergy System	16,037

Competition

General. Entergy and the electric utility industry are experiencing increased competitive pressures in both the retail and wholesale markets. The economic, social, and political forces behind these competitive pressures are numerous and complex. These pressures include legislative and regulatory changes, technological advances, consumer demands, greater availability of natural gas, environmental needs, and other factors. These competitive pressures present opportunities to compete for new customers, as well as risks for loss of customers.

On October 24, 1992, Congress passed the EPAct. The EPAct addresses a wide range of energy issues and alters the way Entergy and the rest of the electric utility industry will operate in the future. The EPAct creates exemptions from regulation under the Holding Company Act and creates a class of EWG's consisting of utility affiliates and nonutilities that own and operate facilities for the generation and transmission of power for sales at wholesale. The EPAct also gives FERC the authority to order investor-owned utilities, including the System operating companies, to transmit power and energy to or for wholesale purchasers and sellers. This creates the potential for electric utilities and other power producers to gain increased access to the transmission systems of other entities to facilitate wholesale sales. FERC may also require electric utilities to increase their transmission capacity to provide these services. The System operating companies jointly filed open access transmission service tariffs with FERC, and subsequent modifications to such tariffs were filed in October 1994 in order to bring the companies into compliance with FERC's evolving "comparability" standard for transmission. For further information, see "Rate Matters and Regulation - Rate Matters - Wholesale Rate Matters," below.

Retail wheeling, the transmission by an electric utility of energy produced by another entity over the utility's transmission and distribution system to a retail customer in the electric utility's area of service, is also evolving. Over a dozen states have been or are studying the concept of retail competition. In April 1994, the state of Michigan initiated a five-year experiment that allows limited competition among public utilities. During the same month, the California Public Utilities Commission proposed to deregulate that state's electric power industry, starting on January 1, 1996, to allow the largest industrial customers to select the lowest cost supplier for electricity service. Under the proposal, by the year 2002, smaller companies and residential customers in California would also be able to buy power from any suppliers. The California Public Utilities Commission is currently reviewing its proposal and is expected to make a ruling in the first half of 1995. The retail market for electricity is expected to become more competitive with such moves toward deregulation.

In some areas of the country, municipalities (or comparable entities) whose residents are served at retail by an investor-owned utility pursuant to a franchise are exploring the possibility of establishing new or

extending existing distribution systems or seeking new delivery points in order to serve retail customers, especially large industrial customers, that currently receive service from an investor-owned utility. These options depend on the terms of a utility's franchise as well as on state law and regulation. In addition, FERC's authority to order utilities to transmit for a new or expanding municipal system is limited in certain respects. Where successful, however, the establishment of a municipal system or the acquisition by a municipal system of a utility's customers could result in the inability to recover costs that the utility has incurred in serving those customers.

In mid-1994, FERC issued a notice of proposed rulemaking concerning a regulatory framework for dealing with recovery of stranded costs, such as high cost nuclear generating units, which may be incurred by electric utilities as a result of increased competition. In addition to addressing recovery of stranded costs related to wholesale service, the proposal requested comment as to recovery of retail stranded costs in transmission rates where state regulatory authorities failed to address the issue or were in conflict. Comments and reply comments have been filed, and the matter is pending. The risk of exposure to stranded costs which may result from competition in the industry will depend on the extent and timing of retail competition, the resolution of jurisdictional issues concerning stranded cost recovery, and the extent to which such costs are recovered from departing or remaining customers, among other matters.

Wholesale Competition. Entergy, like other utility systems, has generating capacity and energy available from time to time for sale to other utility systems. Entergy Power owns 809 MW of generating capacity, and the first priority of use for this capacity is for wholesale sales. The System operating companies may use energy from Entergy Power's capacity for native load needs if no wholesale transactions have been scheduled. The System is in competition with other utilities to sell capacity and energy. Given this competition, the ability of the System to sell capacity and energy to other utilities is limited. However, in 1994, the System sold 7,908 million KWH of energy (compared to 8,291 million KWH in 1993) to nonaffiliated utilities. The System also sold 1,213 MW of long-term capacity (compared to 1,234 MW in 1993) to nonaffiliated utilities outside of the area served by the System. These capacity sales represent 6% of the System's net capability at year-end 1994. Under AP&L's and LP&L's Grand Gulf 1 rate orders, and under GSU's River Bend rate order in Louisiana, a portion of the capacity of Grand Gulf 1 and River Bend represents capacity that is available for sale, subject to regulatory approval, to nonaffiliated parties. In some cases, profits from such sales must be shared between ratepayers and shareholders.

As discussed in "Rate Matters and Regulation - Rate Matters - Wholesale Rate Matters - *Open Access Transmission*," below, Entergy Power and the System operating companies have been permitted by FERC to make wholesale capacity sales in bulk power markets at rates based primarily upon negotiation and market conditions rather than cost of service. In order to receive authorization to make such sales, AP&L, LP&L, MP&L, and NOPSI also filed with FERC open access transmission service tariffs. FERC approved this filing, subject to certain modifications. Revisions to the tariffs were filed in December 1993 to recognize GSU's inclusion in the Entergy System. On July 12, 1994, the D.C. Circuit issued an opinion finding that FERC's failure to conduct an evidentiary hearing with respect to the proposed transmission tariffs and related matters was arbitrary and capricious, and that FERC failed to adequately explain its approval of certain provisions in the tariffs, including a provision allowing Entergy to seek recovery in transmission rates of "stranded investment" costs resulting from the provision of transmission service. The case was remanded to FERC for further proceedings. On October 31, 1994, Entergy Services filed revised transmission tariffs with FERC in response to the D.C. Circuit's remand. These tariffs provide both point-to-point and network transmission services and are intended to provide "comparability of service" over the Entergy transmission network. On January 6, 1995, FERC issued an order accepting the tariffs for filing and making them effective, subject to refund. On January 25, 1995, Entergy Services filed revised transmission tariffs in response to FERC's order. In addition, FERC set Entergy's market pricing authority for investigation, thereby making Entergy's market price rate schedules subject to refund. The market price rate investigation has been deferred by FERC until conclusion of the transmission tariff case, and an order is expected to be issued no later than January 15, 1997. It is anticipated that these tariffs will enable any electric utility (as defined in such tariffs) to use Entergy 's integrated transmission system for the transmission of capacity and energy produced and sold by such electric utility or by third parties. Other similar open access transmission tariffs have also been filed with FERC by several

large utility companies or systems and more open access transmission tariffs are anticipated. Concurrently, capacity resources are being developed and used to make wholesale sales from a range of non-traditional sources, including nonutility generators as well as cogenerators and small power producers qualifying under PURPA.

These developments simultaneously produce increased marketing opportunities for utility systems such as Entergy and expose the System to loss of load or reduced sales revenues due to displacement of System sales by alternative suppliers with access to the System's primary areas of service. Entergy Power was formed to compete with other utilities and independent power producers in the bulk power market. As of December 31, 1994, Entergy Power has accumulated total losses from operations of $67.1 million. Entergy Power has entered into several long-term contracts for the sale of capacity and associated energy from its resources and has also made short-term capacity and energy sales. In 1994, Entergy Power sold 460 million KWH of energy to nonaffiliated utilities, and sold 332 MW of capacity, at the time of the Entergy system peak, to nonaffiliated utilities. Entergy Power actively markets its capacity and energy in the bulk power market. The System operating companies and Entergy Power have separate marketing staffs and may on occasion compete for the same bulk power sale opportunities. (See "Corporate Development," above, for information with respect to a wholly-owned subsidiary of Entergy, Entergy Power Development Corporation, organized as an EWG to compete in the wholesale power market.)

Retail Competition. Many of Entergy's industrial customers, whose costs of production are energy-sensitive, have energy alternatives such as fuel switching, cogeneration, and production shifting. Entergy is constantly working with these customers to address their needs. It is the practice of the System operating companies to negotiate the renewal of contracts with large industrial customers prior to their expiration. In certain cases (particularly for GSU), contracts or special tariffs that use flexible pricing have been negotiated with industrial customers to keep these customers on the System. These contracts and tariffs have generally resulted in increased KWH sales at lower margins over incremental cost. While the System operating companies anticipate they will be successful in renegotiating such contracts, there can be no assurance that they will be successful or that future revenues will not be lost to other forms of generation. Since PURPA was enacted in 1978, the System operating companies have been largely successful in retaining industrial load. This competitive challenge will likely increase.

Cogeneration is generally defined as the combined production of electricity and some other useful form of heat, typically steam. Cogenerated power may be either sold by its producer to the local utility at its avoided cost under PURPA, and/or utilized by the cogenerator to displace purchases from the utility. To the extent that cogeneration is used by industrial customers to meet their own power requirements, the System may suffer loss of industrial load. Cogenerated power delivered to the System would be purchased at avoided cost, which for a number of years is expected to be equivalent to avoided energy cost, and, as such, the cost of these purchases would not impact earnings. To date, only a few cogeneration facilities have been installed in areas served by the System, excluding the GSU area of service. Since PURPA was enacted in 1978, the primary purpose of these facilities is to displace power that was purchased from the System. The economic advantage to the customer is generally due to the customer having waste products that can be used as fuel and/or customers that have an attractive electrical thermal ratio. Presently, the loss of load to cogeneration and the amount of cogenerated power delivered under PURPA to the System are not significant, except in GSU's area of service. The System is prepared to participate (subject to regulatory approval) in various phases of the design, construction, procurement, and ownership of cogeneration facilities. The System has entered into several cogeneration deferral agreements with certain of its retail customers, which give the System the right of first refusal to participate in any of such customers' cogeneration activities. Such participation could occur in the event there are individual customers whose long-term interests, along with Entergy's, can best be served by installing cogeneration facilities. No such participation has occurred to date, except by GSU.

Existing qualifying facilities in GSU's area of service are estimated to total approximately 2,400 MWs or over 10% of Entergy's total owned and leased generating capability as of December 31, 1994. GSU believes that no significant load will be lost to cogeneration projects during the next several years; however, GSU is currently negotiating with a large industrial customer whose contract is scheduled to expire in 1997. If the contract is not renewed, GSU would lose approximately $40 million in annual base revenues.

Although GSU has competed in the past for various retail and wholesale customers, the System is not otherwise generally in direct competition with privately-owned or municipally-owned electric utilities for retail sales. A few municipalities within the area of service of the System operating companies distribute electricity within their corporate limits and some of these municipalities generate all or a portion of their requirements. A number of electric cooperative associations or corporations serve a substantial number of retail customers in or adjacent to areas served by the System operating companies. Sales of energy by the System to privately- or municipally-owned utilities amounted to approximately 3.3% of total System energy sales in 1994. As noted above, municipalities in other areas of the country are seeking to expand their customers bases, to find alternate sources of electricity, and/or to set up new distribution systems.

Legislatures and regulatory commissions in several states have considered, or are considering, retail wheeling. Retail wheeling would permit retail customers to purchase electric capacity and/or energy from the electric utility in whose area of service they are located or from other electric utilities or independent power producers. Retail wheeling is not currently required within the Entergy System's area of service. See "Rate Matters and Regulation - Regulation - Other Regulation and Litigation," below for information on proceedings brought by Cajun seeking transmission access to certain of GSU's industrial customers.

Least Cost Planning. The System continues to pursue least cost planning, also known as integrated resource planning, in order to compete more effectively in both retail and wholesale markets. Least cost planning is the development of strategies to add resources to meet future electricity demands reliably and at the lowest possible cost. The least cost planning process includes the study of electric supply- and demand-side options. The resulting plan uses demand-side options, such as changing customer consumption patterns, to limit electricity usage during times of peak demand, thus delaying the need for new capacity resources. Least cost planning offers the potential for the System to minimize customer costs, while providing an opportunity to earn a return.

On December 1, 1992, AP&L, LP&L, MP&L, and NOPSI each filed a Least Cost Plan with its respective regulator, and on July 1, 1993, each company filed a refined action plan with its respective regulator. Each Least Cost Plan detailed the resources that the System intended to use to provide reasonably priced, reliable electric service to its customers over the next 20 years. Such plans included 925 MW of DSM resources, such as programs for efficient air conditioning and heating, high efficiency lighting, and CCLM. The plans also included significant resource additions, but did not contemplate construction of any new generating facilities. All incremental supply-side resources would come from either delayed retirements or repowering of existing generating units. Each Least Cost Plan included specific actions that the System would undertake pursuant to regulatory approval, including the recovery of costs associated with DSM.

In 1994, the System substantially revised the approach to least cost planning that was used to prepare the above December 1, 1992 and July 1, 1993 filings made with the APSC, LPSC, MPSC, and the Council. At MP&L's request, the MPSC dismissed MP&L's Least Cost Plan filing without prejudice. AP&L and LP&L have requested that their respective retail regulators allow the withdrawal of their Least Cost Plans. Furthermore, AP&L, LP&L, MP&L, and NOPSI have requested that their retail regulators allow for significant changes in the integrated planning process and filings.

The System remains committed to employing integrated resource planning tools. However, the increasingly competitive nature of the market place for electric services mandates changes in the planning process. First, the System has indicated that it intends to use the Ratepayer Impact Measure (RIM) as the screening criterion for all DSM programs, including those DSM measures targeted at strategic load growth. This criterion was adopted because programs selected under this screen will minimize the rate impacts of any programs on all customers. Second, the System has indicated that it will not seek special rate treatment, such as rate riders, for the costs of programs or to compensate for lost revenues as a result of DSM for programs selected using the RIM criterion. Finally, the System has indicated that it will file with the retail regulators, for informational purposes only, a revised integrated resource plan in the fourth quarter of 1995 (for further information, see "Rate Matters and Regulation - Rate Matters - Retail Rate Matters," below).

CAPITAL REQUIREMENTS AND FUTURE FINANCING

Construction expenditures by company (including environmental expenditures, which are immaterial, and AFUDC, but excluding nuclear fuel) for the period 1995-1997 are estimated as follows:

	1995	1996	1997	Total
		(In Millions)		
AP&L	$155	$155	$155	$ 465
GSU	177	177	177	531
LP&L	115	115	115	345
MP&L	68	68	68	204
NOPSI	29	29	29	87
System Energy	22	22	19	63
Entergy Power	2	2	2	6
System	$568	$568	$565	$1,701

No significant construction costs are expected in connection with the System's generating facilities. Actual construction costs may vary from these estimates because of a number of factors, including changes in load growth estimates, changes in environmental regulations, modifications to nuclear units to meet regulatory requirements, increasing costs of labor, equipment and materials, and cost of capital.

In addition to construction expenditure requirements, the estimated amounts required during 1995-1997 to meet scheduled long-term debt and preferred stock maturities and cash sinking fund requirements are: AP&L - $107 million; GSU - $375 million; LP&L - $160 million; MP&L - $253 million; NOPSI - $93 million; and System Energy - $365 million. A substantial portion of these capital and refinancing requirements is expected to be satisfied from internally generated funds and cash on hand, supplemented by the issuance of debt and preferred stock. Certain System companies may also continue with the acquisition or refinancing of all, or a portion of, certain outstanding series of preferred stock and long-term debt in order to achieve cost savings.

Entergy Corporation's current primary capital requirements are to invest periodically in, or make loans to, its subsidiaries. Entergy Corporation has SEC authorization to make additional investments in Entergy Power, Entergy S.A., and Entergy Argentina, S.A., and has applied for authorization to make additional investments in Entergy SASI and Entergy Enterprises. Entergy Corporation expects to meet these capital requirements in 1995-1997 with internally generated funds and cash on hand. Entergy receives funds through dividend distributions from its subsidiaries. Certain restrictions may limit the amount of these distributions. See Entergy Corporation and Subsidiaries' Notes to Consolidated Financial Statements, Note 2, "Rate and Regulatory Matters" and Note 8, "Commitments and Contingencies," regarding River Bend rate appeals and pending litigation with Cajun. Substantial write-offs or charges resulting from adverse rulings in these matters could adversely affect GSU's ability to continue to pay dividends.

Entergy Corporation continues to consider new opportunities to expand its electric energy business, including expansion into related nonregulated businesses. Entergy Corporation may invest up to approximately $150 million per year over the next several years in nonregulated business opportunities. Entergy Corporation expects to fund these investments using internally generated funds and cash on hand. Also, Entergy Corporation may repurchase, from time to time, shares of its outstanding common stock. Market conditions and board authorization determine the amount of repurchases. Entergy Corporation has requested, but has not yet received, SEC authorization for a $300 million bank line of credit, the proceeds of which may be used for common stock repurchases and other investment activities. In addition, Entergy Corporation's non-regulated businesses may seek external financing, subject to receipt of any necessary regulatory approval.

(For further information on the capital and refinancing requirements, capital resources, and short-term borrowing arrangements of AP&L, GSU, LP&L, MP&L, NOPSI, and System Energy, respectively, refer in each case to AP&L's, GSU's, LP&L's, MP&L's, NOPSI's, and System Energy's "Management's Financial Discussion and Analysis - Liquidity and Capital Resources," Note 4 of AP&L's, GSU's, LP&L's, MP&L's, NOPSI's, and System Energy's Notes to Financial Statements, "Lines of Credit and Related Borrowings," Note 5 of AP&L's and NOPSI's Notes to Financial Statements, "Preferred Stock," Note 5 of GSU's Notes to Financial Statements, "Preferred, Preference and Common Stock," Note 5 of LP&L's and MP&L's Notes to Financial Statements, "Preferred and Common Stock," Note 6 of AP&L's, GSU's, LP&L's, MP&L's, and NOPSI's and Note 5 of System Energy's Notes to Financial Statements, "Long-Term Debt," and Note 8 of AP&L's, GSU's, LP&L's, MP&L's, and NOPSI's and Note 7 of System Energy's Notes to Financial Statements, "Commitments and Contingencies - Capital Requirements and Financing." For further information concerning Entergy Corporation's capital requirements and resources, refer to Entergy Corporation and Subsidiaries' "Management's Financial Discussion and Analysis - Liquidity and Capital Resources," and Note 4 of Entergy Corporation and Subsidiaries' Notes to Consolidated Financial Statements, "Lines of Credit and Related Borrowings.")

Certain System Financial and Support Agreements

Unit Power Sales Agreement. The Unit Power Sales Agreement allocates capacity and energy from System Energy's 90% ownership and leasehold interests in Grand Gulf 1 (and the costs related thereto) to AP&L (36%), LP&L (14%), MP&L (33%), and NOPSI (17%), respectively. AP&L, LP&L, MP&L, and NOPSI pay rates to System Energy for their respective entitlements of capacity and energy on a full cost-of-service basis regardless of the quantity of energy delivered, so long as Grand Gulf 1 remains in commercial operation. Payments under the Unit Power Sales Agreement are System Energy's only source of operating revenues. The financial condition of System Energy depends upon the continued commercial operation of Grand Gulf 1 and upon the receipt of payments from AP&L, LP&L, MP&L, and NOPSI. (See "Rate Matters and Regulation - Rate Matters - Wholesale Rate Matters - *System Energy.*" below for further information with respect to proceedings relating to the Unit Power Sales Agreement.)

Availability Agreement. The Availability Agreement was entered into among System Energy and AP&L, LP&L, MP&L, and NOPSI in 1974 in connection with the financing by System Energy of the Grand Gulf Station. The agreement provided that System Energy would join in the agreement among AP&L, LP&L, MP&L, and NOPSI for the sharing of generating capacity and other capacity and energy resources on or before the date on which Grand Gulf 1 was placed in commercial operation. It also provided that System Energy would make available to AP&L, LP&L, MP&L, and NOPSI all capacity and energy available from System Energy's share of the Grand Gulf Station. System Energy and AP&L, LP&L, MP&L, and NOPSI further agreed that if the Availability Agreement were terminated, or if any of the parties thereto withdrew from it, then System Energy would enter into a separate agreement with all such parties or the withdrawing party, as the case may be, with respect to the purchase of capacity and energy on the same terms as if the Availability Agreement were still controlling.

AP&L, LP&L, MP&L, and NOPSI also agreed severally to pay System Energy monthly for the right to receive capacity and energy available from the Grand Gulf Station in amounts that (when added to any amounts received by System Energy under the Unit Power Sales Agreement, or otherwise) would be at least equal to System Energy's total operating expenses for the Grand Gulf Station (including depreciation at a specified rate) and interest charges.

As amended to date, the Availability Agreement provides that:

- the obligations of AP&L, LP&L, MP&L, and NOPSI for payments for Grand Gulf 1 became effective upon commercial operation of Grand Gulf 1 on July 1, 1985;

- the sale of capacity and energy generated by the Grand Gulf Station may be governed by a separate power purchase agreement among System Energy and AP&L, LP&L, MP&L, and NOPSI;

- the September 1989 write-off of System Energy's investment in Grand Gulf 2, amounting to approximately $900 million, will be amortized for Availability Agreement purposes over 27 years rather than in the month the write-off was recognized on System Energy's books; and

- the allocation percentages under the Availability Agreement are fixed as follows: AP&L - 17.1%; LP&L - 26.9%; MP&L - 31.3%; and NOPSI - 24.7%.

As noted above, the Unit Power Sales Agreement provides for different allocation percentages for sales of capacity and energy from Grand Gulf 1. However, the allocation percentages under the Availability Agreement remain in effect and would govern payments made thereunder in the event of a shortfall of funds available to System Energy from other sources, including payments by AP&L, LP&L, MP&L, and NOPSI to System Energy under the Unit Power Sales Agreement.

System Energy has assigned its rights to payments and advances from AP&L, LP&L, MP&L, and NOPSI under the Availability Agreement as security for its first mortgage bonds and reimbursement obligations to certain banks providing the letters of credit in connection with the equity funding of the sale and leaseback transactions described under "Sale and Leaseback Arrangements - *System Energy*," below. In these assignments, AP&L, LP&L, MP&L, and NOPSI further agreed that, in the event they were prohibited by governmental action from making payments under the Availability Agreement (if, for example, FERC reduced or disallowed such payments as constituting excessive rates; see the second succeeding paragraph), they would then make subordinated advances to System Energy in the same amounts and at the same times as the prohibited payments. System Energy would not be allowed to repay these subordinated advances so long as it remained in default under the related indebtedness or in other similar circumstances.

Each of the assignment agreements relating to the Availability Agreement provides that AP&L, LP&L, MP&L, and NOPSI shall make payments directly to System Energy. However, if there is an event of default, AP&L, LP&L, MP&L, and NOPSI must make those payments directly to the holders of indebtedness secured by such assignment agreements. The payments must be made pro rata according to the amount of the respective obligations secured.

The obligations of AP&L, LP&L, MP&L, and NOPSI to make payments under the Availability Agreement are subject to the receipt and continued effectiveness of all necessary regulatory approvals. Sales of capacity and energy under the Availability Agreement would require that the Availability Agreement be submitted to FERC for approval with respect to the terms of such sale. No filing with FERC has been made because sales of capacity and energy from the Grand Gulf Station are being made pursuant to the Unit Power Sales Agreement. Other aspects of the Availability Agreement, including the obligations of AP&L, LP&L, MP&L, and NOPSI to make subordinated advances, are subject to the jurisdiction of the SEC under the Holding Company Act, whose approval has been obtained. If, for any reason, sales of capacity and energy are made in the future pursuant to the Availability Agreement, the jurisdictional portions of the Availability Agreement would be submitted to FERC for approval. (Refer to the second preceding paragraph.)

Amounts that have been received by System Energy under the Unit Power Sales Agreement have exceeded the amounts payable under the Availability Agreement. Consequently, no payments under the Availability Agreement by AP&L, LP&L, MP&L, and NOPSI have ever been required. If AP&L, LP&L, MP&L, or NOPSI became unable in whole or in part to continue making payments to System Energy under the Unit Power Sales Agreement, and System Energy were unable to procure funds from other sources sufficient to cover any potential shortfall between the amount owing under the Availability Agreement and the amount of continuing payments under the Unit Power Sales Agreement plus other funds then available to System Energy, LP&L and NOPSI could become subject to claims or demands by System Energy or its creditors for payments or advances under the Availability Agreement (or the assignments thereof) equal to the difference between their required Unit Power Sales Agreement payments and their required Availability Agreement payments. The amount, if any, that these companies would become liable to pay or advance, over and above amounts they would pay under the Unit Power

Sales Agreement for capacity and energy from Grand Gulf 1, would depend on a variety of factors, including, but not limited to, the amount of any such shortfall and System Energy's access to other funds. It cannot be predicted whether any such claims or demands, if made and upheld, could be satisfied. In NOPSI's case, if any such claims or demands were upheld, the holders of certain of NOPSI's outstanding general and refunding mortgage bonds could require redemption of their bonds at par. The ability of AP&L, LP&L, MP&L, and NOPSI to sustain payments under the Availability Agreement and the assignments thereof in material amounts without substantially equivalent recovery from their customers would be limited by their respective available cash resources and financing capabilities at the time.

The ability of AP&L, LP&L, MP&L, and NOPSI to recover from their customers payments made under the Availability Agreement, or under the assignments thereof, would depend upon the outcome of regulatory proceedings before the state and local regulatory authorities having jurisdiction. In view of the controversies that arose over the allocation of capacity and energy from Grand Gulf 1 pursuant to the Unit Power Sales Agreement, opposition to recovery would be likely and the outcome of such proceedings, should they occur, is not predictable.

Reallocation Agreement. On November 18, 1981, the SEC authorized LP&L, MP&L, and NOPSI to indemnify AP&L against its responsibilities and obligations with respect to the Grand Gulf Station contained in the Availability Agreement and the assignments thereof. The revised percentages of allocated capacity of System Energy's share of Grand Gulf 1 and Grand Gulf 2 were, respectively: LP&L - 38.57% and 26.23%; MP&L - 31.63% and 43.97%; and NOPSI - 29.80% and 29.80%. FERC's decision allocating the capacity and energy of Grand Gulf 1 among AP&L, LP&L, MP&L, and NOPSI supersedes the Reallocation Agreement insofar as it relates to Grand Gulf 1. However, responsibility for any Grand Gulf 2 amortization amounts (see *"Availability Agreement,"* above) has been allocated to LP&L - 26.23%, MP&L - 43.97%, and NOPSI - 29.80%, under the terms of the Reallocation Agreement. The Reallocation Agreement does not affect the obligation of AP&L to System Energy's lenders under the assignments referred to in the fifth preceding paragraph, and AP&L would be liable for its share of such amounts if LP&L, MP&L, and NOPSI were unable to meet their contractual obligations. No payments of any amortization amounts will be required as long as amounts paid to System Energy under the Unit Power Sales Agreement, together with other funds available to System Energy, exceed amounts required under the Availability Agreement. This is expected to be the case for the foreseeable future.

Capital Funds Agreement. System Energy and Entergy Corporation have entered into the Capital Funds Agreement whereby Entergy Corporation has agreed to supply to System Energy sufficient capital to (1) maintain System Energy's equity capital at an amount equal to a minimum of 35% of its total capitalization (excluding short-term debt), and (2) permit the continuation of commercial operation of Grand Gulf 1 and to pay in full all indebtedness for borrowed money of System Energy when due under any circumstances.

Entergy Corporation has entered into various supplements to the Capital Funds Agreement, and System Energy has assigned its rights thereunder as security for its first mortgage bonds and reimbursement obligations to certain banks providing letters of credit in connection with the equity funding of the sale and leaseback transactions described below under "Sale and Leaseback Arrangements - *System Energy*". Each such supplement provides that permitted indebtedness for borrowed money incurred by System Energy in connection with the financing of the Grand Gulf Station may be secured by System Energy's rights under the Capital Funds Agreement on a pro rata basis (except for the Specific Payments, as hereinafter defined). In addition, in the particular supplements to the Capital Funds Agreement relating to the specific indebtedness being secured, Entergy Corporation has agreed to make cash capital contributions to System Energy sufficient to enable System Energy to make payments when due on such indebtedness (Specific Payments).

Except with respect to the Specific Payments, which have been approved by the SEC under the Holding Company Act, the performance by both Entergy Corporation and System Energy of their obligations under the Capital Funds Agreement, as supplemented, is subject to the receipt and continued effectiveness of all governmental authorizations necessary to permit such performance, including approval by the SEC under the Holding Company Act. Each of the supplemental agreements provides that Entergy Corporation shall make its payments directly to System Energy. However, if there is an event of default, Entergy Corporation must make those payments directly

to the holders of indebtedness secured by the supplemental agreements. The payments (other than the Specific Payments) must be made pro rata according to the amount of the respective obligations secured by the supplemental agreements.

Sale and Leaseback Arrangements

LP&L. On September 28, 1989, LP&L entered into arrangements for the sale and leaseback of an approximate aggregate 9.3% ownership interest in Waterford 3. LP&L has options to terminate the leases and to repurchase the interests in Waterford 3 at certain intervals during the basic terms of the leases. Further, at the end of the terms of the leases, LP&L has options to renew the leases or to repurchase the interests in Waterford 3. LP&L did not exercise its option to repurchase the undivided interests in Waterford 3 on the fifth anniversary (September 1994) of the closing date of the sale and leaseback transactions. As a result, LP&L was required to provide collateral to the owner participants for the equity portion of certain amounts payable by LP&L under the lease. Such collateral was in the form of a new series of first mortgage bonds in the aggregate principal amount of $208.2 million issued by LP&L in September 1994 under its first mortgage bond indenture. (For further information on LP&L's sale and leaseback arrangements, including the required maintenance by LP&L of specified capitalization and fixed charge coverage ratios, see Note 9 of LP&L's Notes to Financial Statements, "Leases - Waterford 3 Lease Obligations.")

System Energy. On December 28, 1988, System Energy entered into arrangements for the sale and leaseback of an approximate aggregate 11.5% ownership interest in Grand Gulf 1. System Energy has options to terminate the leases and to repurchase the undivided interest in Grand Gulf 1 at certain intervals during the basic lease term. Further, System Energy has an option at the end of the basic lease term to renew the leases or to repurchase the undivided interest in Grand Gulf 1. In connection with the equity funding of the sale and leaseback arrangements, letters of credit are required to be maintained by System Energy under the leases to secure certain amounts payable for the benefit of the equity investors. The letters of credit currently maintained are effective until January 15, 1997. Under the provisions of a reimbursement agreement, dated December 1, 1988, as amended, entered into by System Energy and various banks in connection with the sale and leaseback arrangements related to the letters of credit (Reimbursement Agreement), System Energy has agreed to a number of covenants relating to, among other things, the maintenance of certain capitalization and fixed charge ratios. In connection with an audit of System Energy by FERC, in June 1994, System Energy, AP&L, LP&L, MP&L, and NOPSI reached a settlement with the FERC staff and other parties. On November 30, 1994, FERC approved the settlement. In accordance with the settlement, System Energy refunded approximately $61.7 million to AP&L, LP&L, MP&L, and NOPSI, which in turn have made or will make refunds or credits to their customers (except for those portions attributable to AP&L's and LP&L's retained share of Grand Gulf 1 costs). Additionally, System Energy will refund a total of approximately $62 million, plus interest, to AP&L, LP&L, MP&L, and NOPSI over the period through June 2004. AP&L, LP&L MP&L, and NOPSI also wrote-off certain related unamortized balances of deferred tax credits. As a result of the charges associated with the settlement, System Energy obtained the consent of certain banks (parties to the Reimbursement Agreement) to waive the fixed charge coverage covenant in the letters of credit and the Reimbursement Agreement related to the Grand Gulf 1 sale and leaseback transaction, until November 30, 1995. System Energy expects that upon expiration of the waiver period, it will be in compliance with the fixed charge coverage covenant. Absent a waiver, failure by System Energy to perform this covenant could give rise to a draw under the letters of credit and/or an early termination of the letters of credit, and, if such letters of credit were not replaced in a timely manner, could result in a default under, or other early termination of, System Energy's leases. (For further information on the effects of the settlement on System Energy's financial condition, see Note 2 of System Energy's Notes to Financial Statements, "Rate and Regulatory Matters - FERC Audit," and for a further discussion of the provisions of System Energy's Reimbursement Agreement, see System Energy's Notes to Financial Statements, Note 6, "Dividend Restrictions" and Note 7, "Commitments and Contingencies - Reimbursement Agreement.")

RATE MATTERS

The System operating companies' retail rates are regulated by their respective state and/or local regulatory authorities, as described below, and their rates for wholesale sales (including intrasystem sales pursuant to the System Agreement) and interstate transmission of electricity are regulated by FERC. Rates for System Energy's sales of capacity and energy from Grand Gulf 1 to AP&L, LP&L, MP&L, and NOPSI pursuant to the Unit Power Sales Agreement are also regulated by FERC.

Wholesale Rate Matters

GSU. For information, see "Retail Rate Matters - GSU," below and "Regulation - Other Regulation and Litigation - *GSU*," below.

System Energy. As described above under "Certain System Financial and Support Agreements," System Energy recovers costs related to its interest in Grand Gulf 1 through rates charged to AP&L, LP&L, MP&L, and NOPSI for Grand Gulf 1 capacity and energy under the Unit Power Sales Agreement.

In November 1994, FERC approved an agreement settling a long-standing dispute involving income tax allocation procedures of System Energy. In accordance with the agreement, System Energy refunded approximately $61.7 million to AP&L, LP&L, MP&L, and NOPSI, which in turn have made or will make refunds or credits to their customers (except for those portions attributable to AP&L's and LP&L's retained share of Grand Gulf 1 costs). Additionally, System Energy will refund a total of approximately $62 million, plus interest, to AP&L, LP&L, MP&L, and NOPSI over the period through June 2004. The settlement also required the write-off of certain related unamortized balances of deferred investment tax credits by AP&L, LP&L, MP&L, and NOPSI. The settlement reduced Entergy Corporation's consolidated net income for the year ended December 31, 1994, by approximately $68.2 million, offset by the write-off of the unamortized balances of related deferred investment tax credits of approximately $69.4 million ($2.9 million for Entergy Corporation; $27.3 million for AP&L; $31.5 million for LP&L; $6 million for MP&L; and $1.7 million for NOPSI). System Energy also reclassified from utility plant to other deferred debits approximately $81 million of other Grand Gulf 1 costs. Although excluded from rate base, System Energy will be permitted to recover such costs over a 10-year period. Interest on the $62 million refund and the loss of the return on the $81 million of other Grand Gulf 1 costs will reduce Entergy's and System Energy's net income by approximately $10 million annually over the next 10 years. For further information, see Note 2 of System Energy's Notes to Financial Statements and Note 2 of Entergy Corporation and Subsidiaries' Notes to Consolidated Financial Statements, "Rate and Regulatory Matters - FERC Settlement."

Entergy Power. In 1990, authorizations were obtained from the SEC, FERC, the APSC, and the Public Service Commission of Missouri for Entergy Power to purchase AP&L's interests in Independence 2 and Ritchie 2, and to begin marketing the capacity and energy from the units in certain wholesale markets. The SEC order approving various aspects of the transaction was appealed by various intervenors in the proceeding to the D.C. Circuit, which reversed a portion of the order and remanded the case to the SEC for consideration of the effect of the transfers on the System's future costs of replacement generating capacity and fuel. In response to a June 24, 1993 SEC order setting a procedural schedule for the filing of further pleadings in the proceeding, in July 1993, the Entergy parties filed a post-effective amendment to their application addressing the issues specified in the SEC order. On September 9, 1993, the City of New Orleans and the LPSC each requested a hearing. However, on January 5, 1994, the City of New Orleans withdrew from the proceeding, as agreed in its settlement with NOPSI of various issues related to the Merger. The matter is pending before the SEC on remand.

System Agreement. AP&L, LP&L, MP&L, and NOPSI engage in the coordinated planning, construction, and operation of generation and transmission facilities pursuant to the terms of the System Agreement (described

under "Property - Generating Stations," below). GSU became a party to the System Agreement upon consummation of the Merger, and GSU now participates in this System-wide coordination.

In connection with the Merger, FERC approved certain rate schedule changes to integrate GSU into the System Agreement. Certain commitments were adopted to provide reasonable assurance that the ratepayers of AP&L, LP&L, MP&L, and NOPSI will not be allocated higher costs, including, among other things: (1) a tracking mechanism to protect operating companies from certain unexpected increases in fuel costs; (2) excluding GSU from the distribution of profits from power sales contracts entered into prior to the Merger; (3) a methodology to estimate the cost of capital in future FERC proceedings; and (4) a stipulation that the operating companies will be insulated from certain direct effects on capacity equalization payments should GSU acquire Cajun's 30% share in River Bend. See "Regulation - Other Regulation and Litigation" for information on appeals of FERC Merger orders and related pending rate schedule changes.

In the December 15, 1993, order approving the Merger, FERC also initiated a new proceeding to consider whether the System Agreement permits certain out-of-service generating units to be included in reserve equalization calculations under Service Schedule MSS-1 of that agreement. FERC established March 8, 1994, as the refund effective date. On February 16, 1994, Entergy Corporation filed an Offer of Settlement to amend the System Agreement prospectively to make it explicit that certain out-of-service generating units may be included in reserve equalization calculations under Service Schedule MSS-1. The LPSC and MPSC contested certain provisions in the proposal, and also argued that LP&L and MP&L were entitled to refunds for MSS-1 payments made in the past. Subsequently, the LPSC and MPSC submitted testimony based on estimates, seeking refunds estimated at $22.6 million and $13.2 million, respectively. On March 31, 1994, the ALJ limited the scope of the hearing to exclude any claims for retroactive refunds. On April 5, 1994, the LPSC, Mississippi Attorney General (MAG), and MPSC filed a complaint with FERC claiming that Entergy's past reserve equalization charges under System Agreement Schedule MSS-1 violated the System Agreement, sought refunds and requested FERC to hold a hearing to consider this claim. Responses by Entergy Corporation and other parties were filed on April 26, 1994. On June 17, 1994, FERC issued an order that clarified the scope of the proceeding to include a review of whether refunds are due for periods prior to the refund effective date.

The FERC staff submitted testimony concluding that although Entergy's treatment was reasonable, because it violated the tariff, refunds of approximately $7.2 million should be ordered. Entergy submitted testimony on September 23, 1994, describing the potential impacts (not including interest) on Service Schedule MSS-1 calculations if extended reserve shutdown units were not included in the MSS-1 calculations during the period 1987 through 1993. Under such a theory, LP&L and MP&L would have been overbilled by $10.6 and $8.8 million, respectively, and AP&L and NOPSI would have been underbilled by $6.3 and $13.1 million, respectively. The amounts potentially subject to refund will continue to accrue while the case is pending. Entergy believes that its calculation of MSS-1 charges has been and will continue to be, in compliance with the System Agreement, and that no refunds are due. An initial decision is expected in March 1995.

On August 20, 1990, the City of New Orleans filed a complaint against Entergy Corporation, AP&L, LP&L, MP&L, NOPSI, and System Energy requesting that FERC investigate AP&L's transfer of its interest in Independence 2 and Ritchie 2 to Entergy Power (see "Entergy Power," above) and the effect of the transfer on AP&L, LP&L, MP&L, NOPSI, and their ratepayers. Various parties, including certain of the System's state regulators, intervened in the proceeding. FERC issued an order on March 19, 1991, setting for investigation (1) the question of whether overall billings under the System Agreement will increase as a result of the transfer to Entergy Power, and (2) if so, whether such increased billings reflect prudently incurred costs that may reasonably be charged under the System Agreement. In two separate decisions the FERC ALJ ruled on May 14, 1992 and October 30, 1992, respectively, that there was sufficient evidence to show that overall billings would increase as a result of the transfer, but that the transfer was prudent. On December 15, 1993, FERC issued an opinion declining to address the prudence issue until a future time when replacement capacity has been added or planned and finding that, until such time, billings under the System Agreement as affected by the transfer of the two units are reasonable. The Entergy parties and the City each filed a request for rehearing of this order, which was denied

by FERC on February 28, 1994. The Entergy parties and the City each filed an appeal of the FERC's orders with the D.C. Circuit. Various parties have intervened. If FERC's decision were reversed and any refunds were ordered, they would be retroactive to October 19, 1990.

On March 15, 1995, the LPSC filed a complaint with FERC alleging that the System Agreement results in unjust and unreasonable rates and requested that FERC order a hearing on this matter. The LPSC contends that the failure of the System Agreement to exclude curtailable load from the determination of a System operating company's responsibility for reserve equalization and transmission equalization costs results in an unjust and unreasonable cost allocation to the companies that do not cause these costs to be incurred, and also results in cross-subsidization among the System operating companies. Further, the LPSC alleges that the mechanism by which the System operating companies purchase energy under the System Agreement results in unjust and unreasonable rates because it does not permit companies that engage in real time pricing to be charged the marginal cost of the energy generated for the real time pricing customer. The System is currently evaluating the merits of the LPSC's complaint.

Open Access Transmission. On August 2, 1991, Entergy Services, as agent for AP&L, LP&L, MP&L, NOPSI, and Entergy Power, submitted to FERC (1) proposed tariffs that, subject to certain conditions, would provide to electric utilities "open access" to the System's integrated transmission system, and (2) rate schedules providing for sales of wholesale power at market-based rates. Under FERC policy, sales of power at market-based rates would be permitted only if FERC found, among other things, that Entergy did not have market power over transmission. Permitting "open access" to the System's transmission system helps support such a finding. Various parties, including the Council, the APSC, the MPSC, and the LPSC, intervened in the proceeding. On March 3, 1992, FERC approved the filing, with some modifications, and on August 7, 1992, FERC denied rehearing of its March 1992 order. On August 24, 1992, various parties filed petitions with the D.C. Circuit for review of FERC's 1992 orders, and these petitions were consolidated. The revised tariffs, submitted by Entergy Services in response to FERC's 1992 orders, were accepted for filing and made effective, subject to further modifications, by order dated April 5, 1993. Entergy Services made a further compliance filing on May 5, 1993, reflecting these modifications and requesting reconsideration of certain limited matters, which is subject to approval by FERC. On December 31, 1993, Entergy Services filed revisions to the transmission service tariff to recognize GSU's inclusion in the Entergy System.

On July 12, 1994, the D.C. Circuit issued an opinion finding that FERC's failure to conduct an evidentiary hearing with respect to the proposed transmission tariffs and related matters was arbitrary and capricious, and that FERC failed to adequately explain its approval of certain provisions in the tariffs, including a provision allowing Entergy to seek recovery in transmission rates of "stranded investment" costs resulting from the provision of transmission service. The case was remanded to FERC for further proceedings. On October 31, 1994, Entergy Services filed revised transmission tariffs with FERC in response to the D.C. Circuit's remand. These tariffs provide both point-to-point and network transmission services and are intended to provide "comparability of service" over the Entergy transmission network. On January 6, 1995, FERC issued an order accepting the tariffs for filing and making them effective, subject to refund. On January 25, 1995, Entergy Services filed revised transmission tariffs in response to FERC's order. In addition, FERC set Entergy's market pricing authority for investigation, thereby making Entergy's market price rate schedules subject to refund. The market price rate investigation has been deferred by FERC until conclusion of the transmission tariff case, and an order is expected to be issued no later than January 15, 1997.

Wholesale Contract. In March 1994, North Little Rock, Arkansas, awarded AP&L a wholesale power contract that will provide estimated revenues of $347 million over 11 years. Under the contract, the price per KWH was reduced 18%, with increases in price through the year 2004. AP&L, which has been serving North Little Rock for over 40 years, was awarded the contract after intense bidding with several competitors. On May 22, 1994, FERC accepted the contract. Rehearings were requested by one of AP&L's competitors and were held in February 1995. The matter is pending.

Retail Rate Matters

General. AP&L, LP&L, MP&L, and NOPSI currently have retail rate structures sufficient to recover their costs, including costs associated with their allocated shares of capacity and energy from Grand Gulf 1 under the Unit Power Sales Agreement, and a return on equity. Certain costs related to Grand Gulf 1 (and in LP&L's case, Waterford 3) are being phased into retail rates over a period of time, in order to avoid the "rate shock" associated with increasing rates to reflect all such costs at once. The deferral period in which costs are incurred but not currently recovered has expired for all of these programs, and AP&L, LP&L, MP&L, and NOPSI are now recovering those costs that were previously deferred. Also, AP&L and LP&L have retained a portion of their shares of Grand Gulf 1 capacity and GSU is operating under a deregulated asset plan for a portion of its share of River Bend.

GSU is involved in several rate proceedings involving recovery, among other things, of costs associated with River Bend. Some rate relief has been received, but GSU has been unable to obtain recognition in rates for a substantial portion of its River Bend investment. Recovery of certain costs has been disallowed, while other costs are being deferred for future recovery, held in abeyance pending further regulatory action, or treated as investments in deregulated assets. Rate proceedings and appeals relating to these issues are ongoing (see "GSU," below).

The System is committed to taking actions that will stabilize retail rates and avoid the need for future rate increases. In the short-term, this involves containing costs to the greatest degree practicable, thereby avoiding erosion of earnings and delaying for as long as possible the need for general rate increases. In accordance with this retail rate policy, the System operating companies have agreed to retail rate caps and/or rate freezes for specified periods of time. Also, NOPSI reached a settlement with the Council to reduce electric and gas rates and issue credits and refunds to customers. For further information, see "NOPSI" below.

The retail regulatory philosophy is shifting in some jurisdictions from traditional cost of service regulation to incentive rate regulation. Incentive and performance-based rate plans encourage efficiencies and productivity while permitting utilities and their customers to share in the results. MP&L implemented an incentive rate plan in 1994 and LP&L filed a performance-based formula rate plan with the LPSC in August 1994. For further information, see "LP&L" and "MP&L" below.

In the longer term, as discussed in "Business of Entergy - Competition - *Least Cost Planning*" above, and also as discussed specifically for each applicable company below, the System remains committed to employing integrated resource planning to minimize the cost of future sources of energy.

AP&L

Rate Freeze. In connection with the settlement of various issues related to the Merger, AP&L agreed that it will not request any general retail rate increase that would take effect before November 3, 1998, except for, among other things, increases associated with the recovery of certain Grand Gulf 1-related costs, excess capacity costs, and costs related to the adoption of SFAS 106 that were previously deferred; recovery of certain taxes; fuel adjustment recoveries; recovery of nuclear decommissioning costs; and force majeure (defined to include, among other things, war, natural catastrophes, and high inflation).

Recovery of Grand Gulf 1 Costs. Under the settlement agreement entered into with the APSC in 1985 and amended in 1988, AP&L agreed to retain a portion of its Grand Gulf 1-related costs, recover a portion of such costs currently, and defer a portion of such costs for future recovery. In 1994 and subsequent years, AP&L will retain 7.92% of such costs and will recover 28.08% currently. Deferrals ceased in 1990, and AP&L is recovering a portion of the previously deferred costs each year through 1998. As of December 31, 1994, the balance of deferred uncollected costs was $474.1 million. AP&L is permitted to recover on a current basis the incremental costs of financing the unrecovered deferrals.

AP&L has the right to sell capacity and energy from its retained share of Grand Gulf 1 to third parties and to sell such energy to its retail customers at a price equal to AP&L's avoided energy cost. Proceeds of sales to third parties of AP&L's retained share of Grand Gulf 1 capacity and energy generally accrue to the benefit of AP&L's stockholder; however, half of the proceeds of such sales to third parties prior to January 1, 1996, are used to reduce the balance of uncollected deferrals and thus accrue to the benefit of retail ratepayers. If AP&L makes sales to third parties prior to that date in excess of the retained share, the proceeds of such excess are also split between the stockholder and the ratepayers, except that the portion of the sale that accrues to the stockholder's benefit cannot exceed the retained share.

Least Cost Planning. On December 1, 1992, and July 1, 1993, AP&L filed with the APSC the Least Cost Plan described in "Business of Entergy - Competition - *Least Cost Planning*," above. However, in response to an increasingly competitive electric utility environment AP&L filed a motion on July 1, 1994, requesting that the APSC approve the withdrawal of the December 1, 1992, and July 1, 1993, filings and rescind its directive that AP&L file another Least Cost Plan in March 1995. AP&L will file, for informational purposes only, a revised Least Cost Plan in the fourth quarter of 1995. In this plan, AP&L intends to adopt the RIM as the screening criterion for DSM programs including those DSM measures targeted at strategic load growth. This is in place of the total resource cost test that had been used in developing the initial Least Cost Plan. This criterion was adopted because programs selected under this screen will minimize the rate impact of any programs on all customers. AP&L has indicated that it will not seek special rate treatment, such as rate riders, for the cost of programs or loss of revenues due to DSM programs selected using the RIM criterion. On October 5, 1994, the APSC issued an order that suspended the initial Least Cost Plan dockets and established a new docket to consider the need for integrated resource planning standards as required by the EPAct. Hearings are scheduled to begin in April 1995.

Fuel Adjustment Clause. AP&L's retail rate schedules have a fuel adjustment clause that provides for recovery of the excess cost of fuel and purchased power incurred in the second preceding month. The fuel adjustment clause also contains a nuclear reserve fund designed to cover the cost of replacement energy during scheduled maintenance and refueling outages at ANO, and an incentive provision that permits over- or under-recovery of the excess cost of replacement energy when ANO is operating or down for reasons other than refueling.

GSU

Rate Cap and Other Merger-Related Rate Agreements. In 1993, the LPSC and the PUCT approved separate regulatory proposals that include the following elements: (1) a five-year Rate Cap on GSU's retail electric base rates in the respective states, except for force majeure (defined to include, among other things, war, natural catastrophes, and high inflation); (2) a provision for passing through to retail customers in the respective states the jurisdictional portion of the fuel savings created by the Merger; and (3) a mechanism for tracking nonfuel operation and maintenance savings created by the Merger. The LPSC regulatory plan provides that such nonfuel savings will be shared 60% by the shareholder and 40% by ratepayers during the eight years following the Merger. The LPSC plan requires regulatory filings each year by the end of May through 2001. The PUCT regulatory plan provides that such savings will be shared equally by the shareholder and ratepayers, except that the shareholder's portion will be reduced by $2.6 million per year on a total company basis in years four through eight. The PUCT plan also requires a series of future regulatory filings in November 1996, 1998, and 2001, to ensure that ratepayers' share of such savings be reflected in rates on a timely basis and requires Entergy Corporation to hold GSU's Texas retail customers harmless from the effects of the removal by FERC of a 40% cap on the amount of fuel savings GSU may be required to transfer to other Entergy operating companies under the FERC tracking mechanism (see below). On January 14, 1994, Entergy Corporation filed a request for rehearing of FERC's December 15, 1993, order approving the Merger requesting that FERC restore the 40% cap provision in the fuel cost protection mechanism. The matter is pending.

Recovery of River Bend Costs. GSU deferred approximately $369 million of River Bend operating costs, purchased power costs, and accrued carrying charges pursuant to a 1986 PUCT accounting order. Approximately

$182 million of these costs are being amortized over a 20-year period ending in the year 2009, and the remaining $187 million are not being amortized pending the ultimate outcome of the Rate Appeal (see "*Texas Jurisdiction - River Bend*," below). As of December 31, 1994, the unamortized balance of these costs was $321 million. Further, GSU deferred approximately $400.4 million of similar costs pursuant to a 1986 LPSC accounting order. These costs, of which approximately $122 million are unamortized as of December 31, 1994, are being amortized over a 10-year period ending in 1997.

In accordance with a phase-in plan approved by the LPSC, GSU deferred $294 million of its River Bend costs related to the period February 1988 through February 1991. GSU has amortized $129 million through December 31, 1994, and the remainder of $165 million will be recovered over approximately 3.2 years.

Texas Jurisdiction - River Bend. In May 1988, the PUCT granted GSU a permanent increase in annual revenues of $59.9 million resulting from the inclusion in rate base of approximately $1.6 billion of company-wide River Bend plant investment and approximately $182 million of related Texas retail jurisdiction deferred River Bend costs (Allowed Deferrals). In addition, the PUCT disallowed as imprudent $63.5 million of company-wide River Bend plant costs and placed in abeyance, with no finding of prudence, approximately $1.4 billion of company-wide River Bend plant investment and approximately $157 million of Texas retail jurisdiction deferred River Bend operating and carrying costs. The PUCT affirmed that the ultimate rate treatment of such amounts would be subject to future demonstration of the prudence of such costs. GSU and intervening parties appealed this order (Rate Appeal) and GSU filed a separate rate case asking that the abeyed River Bend plant costs be found prudent (Separate Rate Case). Intervening parties filed suit in a Texas district court to prohibit the Separate Rate Case. The district court's decision was ultimately appealed to the Texas Supreme Court, which ruled in 1990 that the prudence of the purported abeyed costs could not be relitigated in a separate rate proceeding. The Texas Supreme Court's decision stated that all issues relating to the merits of the original PUCT order, including the prudence of all River Bend-related costs, should be addressed in the Rate Appeal.

In October 1991, the Texas district court in the Rate Appeal issued an order holding that, while it was clear the PUCT made an error in assuming it could set aside $1.4 billion of the total costs of River Bend and consider them in a later proceeding, the PUCT, nevertheless, found that GSU had not met its burden of proof related to the amounts placed in abeyance. The court also ruled that the Allowed Deferrals should not be included in rate base. The court further stated that the PUCT had erred in reducing GSU's deferred costs by $1.50 for each $1.00 of revenue collected under the interim rate increases authorized in 1987 and 1988. The court remanded the case to the PUCT with instructions as to the proper handling of the Allowed Deferrals. GSU's motion for rehearing was denied and, in December 1991, GSU filed an appeal of the October 1991 district court order. The PUCT also appealed the October 1991 district court order, which served to supersede the district court's judgment, rendering it unenforceable under Texas law.

In August 1994, the Texas Third District Court of Appeals (the Appellate Court) affirmed the district court's decision that there was substantial evidence to support the PUCT's 1988 decision not to include the abeyed construction costs in GSU's rate base. While acknowledging that the PUCT had exceeded its authority when it attempted to defer a decision on the inclusion of those costs in rate base in order to allow GSU a further opportunity to demonstrate the prudence of those costs in a subsequent proceeding, the Appellate Court found that GSU had suffered no harm or lack of due process as a result of the PUCT's error. Accordingly, the Appellate Court held that the PUCT's action had the effect of disallowing the company-wide $1.4 billion of River Bend construction costs for ratemaking purposes. In its August 1994 opinion, the Appellate Court also held that GSU's deferred operating and maintenance costs associated with the allowed portion of River Bend should be included in rate base and that GSU's deferred River Bend carrying costs included in the Allowed Deferrals should also be included in rate base. The Appellate Court's August 1994 opinion affirmed the PUCT's original order in this case.

The Appellate Court's August 1994 opinion was entered by two judges, with a third judge dissenting. The dissenting opinion states that the result of the majority opinion is, among other things, to deprive GSU of due process at the PUCT because the PUCT never reached a finding on the $1.4 billion of construction costs.

In October 1994, the Appellate Court denied GSU's motion for rehearing on the August 1994 opinion as to the $1.4 billion in River Bend construction costs and other matters. GSU appealed the Appellate Court's decision to the Texas Supreme Court, where it is pending.

As of December 31, 1994, the River Bend plant costs disallowed for retail ratemaking purposes in Texas, the River Bend plant costs held in abeyance, and the related operating and carrying cost deferrals totaled (net of taxes) approximately $13 million, $280 million (both net of depreciation), and $170 million, respectively. Allowed Deferrals were approximately $107 million, net of taxes and amortization, as of December 31, 1994. GSU estimates it has collected approximately $158 million of revenues as of December 31, 1994, as a result of the originally ordered rate treatment by the PUCT of these deferred costs. If recovery of the Allowed Deferrals is not upheld, future revenues based upon those allowed deferrals could also be lost, and no assurance can be given as to whether or not refunds of revenue received based upon such deferred costs previously recorded will be required.

No assurance can be given as to the timing or outcome of the remands or appeals described above. Pending further developments in these cases, GSU has made no write-offs or reserves for the River Bend-related costs. Management believes, based on advice from Clark, Thomas & Winters, a Professional Corporation, legal counsel of record in the Rate Appeal, that it is reasonably possible that the case will be remanded to the PUCT, and the PUCT will be allowed to rule on the prudence of the abeyed River Bend plant costs. Rate Caps imposed by the PUCT's regulatory approval of the Merger could result in GSU being unable to use the full amount of a favorable decision to immediately increase rates; however, a favorable decision could permit some increases and/or limit or prevent decreases during the period the Rate Caps are in effect. At this time, management and legal counsel are unable to predict the amount, if any, of the abeyed and previously disallowed River Bend plant costs that ultimately may be disallowed by the PUCT. A net of tax write-off as of December 31, 1994, of up to $293 million could be required based on an ultimate adverse ruling by the PUCT on the abeyed and disallowed costs.

In prior proceedings, the PUCT has held that the original cost of nuclear power plants will be included in rates to the extent those costs were prudently incurred. Based upon the PUCT's prior decisions, management believes that its River Bend construction costs were prudently incurred and that it is reasonably possible that it will recover in rate base, or otherwise through means such as a deregulated asset plan, all or substantially all of the abeyed River Bend plant costs. However, management also recognizes that it is reasonably possible that not all of the abeyed River Bend plant costs may ultimately be recovered.

As part of its direct case in the Separate Rate Case, GSU filed a cost reconciliation study prepared by Sandlin Associates, management consultants with expertise in the cost analysis of nuclear power plants, which supports the reasonableness of the River Bend costs held in abeyance by the PUCT. This reconciliation study determined that approximately 82% of the River Bend cost increase above the amount included by the PUCT in rate base was a result of changes in federal nuclear safety requirements and provided other support for the remainder of the abeyed amounts.

There have been four other rate proceedings in Texas involving nuclear power plants. Investment in the plants ultimately disallowed ranged from 0% to 15%. Each case was unique, and the disallowances in each were made on a case-by-case basis for different reasons. Appeals of two of these PUCT decisions are currently pending.

The following factors support management's position that a loss contingency requiring accrual has not occurred, and its belief that all, or substantially all, of the abeyed plant costs will ultimately be recovered:

1. The $1.4 billion of abeyed River Bend plant costs have never been ruled imprudent and disallowed by the PUCT.
2. Sandlin Associates' analysis which supports the prudence of substantially all of the abeyed construction costs.
3. Historical inclusion by the PUCT of prudent construction costs in rate base.
4. The analysis of GSU's internal legal staff, which has considerable experience in Texas rate case litigation.

Additionally, management believes, based on advice from Clark, Thomas & Winters, a Professional Corporation, legal counsel of record in the Rate Appeal, that it is reasonably possible that the Allowed Deferrals will continue to be recovered in rates. Management also believes, based on advice from Clark, Thomas & Winters, a Professional Corporation, legal counsel of record in the Rate Appeal, that it is reasonably possible that the deferred costs related to the $1.4 billion of abeyed River Bend plant costs will be recovered in rates to the extent that the $1.4 billion of abeyed River Bend plant is recovered. However, a net of tax write-off of the $170 million of deferred costs related to the $1.4 billion of abeyed River Bend plant costs would be required if they are not allowed to be recovered in rates.

Texas Fuel Cost Review. (December 1, 1986 - September 30, 1991) In January 1992, GSU applied to the PUCT for a new fixed fuel factor and requested a final reconciliation of fuel and purchased power costs incurred between December 1, 1986 and September 30, 1991. GSU proposed to recover net underrecoveries and interest (including underrecoveries related to NISCO, discussed below) over a twelve month period.

In April 1993, the presiding PUCT ALJ issued a report concluding that GSU incurred approximately $117 million of nonreimbursable fuel costs on a company-wide basis (approximately $50 million on a Texas retail jurisdictional basis) during the reconciliation period. Included in the nonreimbursable fuel costs were payments above GSU's avoided cost rate for power purchased from NISCO. The PUCT ordered in 1986 that the purchased power costs from NISCO in excess of GSU's avoided costs be disallowed. The PUCT disallowance resulted in approximately $12 million to $15 million of unrecovered purchased power costs on an annual basis, which GSU continued to expense as the costs were incurred. In April 1991, the Texas Supreme Court, in the appeal of such order, ordered the PUCT to allow GSU to recover purchased power payments in excess of its avoided cost in future proceedings, if GSU established to the PUCT's satisfaction that the payments were reasonable and necessary expenses.

In June 1993, the PUCT concluded that the purchased power payments made to NISCO in excess of GSU's avoided cost were not reasonably incurred. As a result of the order, GSU recorded additional fuel expenses (including interest) of $2.8 million for non-NISCO related items. The PUCT's order resulted in no additional expenses related to the NISCO issue, or for overcollections related to the fixed fuel factor, as those charges were expensed by GSU as they were incurred. The PUCT concluded that GSU had over-collected its fuel costs in Texas and ordered GSU to refund approximately $33.8 million to its Texas retail customers, including approximately $7.5 million of interest. In that proceeding, the PUCT also set GSU's fixed fuel factor in Texas at 1.84 cents per KWH in response to GSU's request that the factor be set at 2.02 cents per KWH. In October 1993, GSU appealed the PUCT's order to the Travis County District Court where the matter is still pending. No assurance can be given as to the timing or outcome of that appeal. In a subsequent proceeding to review GSU's fuel factor, the PUCT approved GSU's request to further reduce its fixed fuel factor in Texas to 1.78 cents per KWH from 1.84 cents per KWH.

Texas Fuel Cost Review. (October 1, 1991 - December 31, 1993) On January 9, 1995, GSU and various parties reached an agreement for the reconciliation of over- and under-recovery of fuel and purchased power expenses for the period October 1, 1991, through December 31, 1993. While the settlement still requires PUCT approval, GSU believes it will ultimately be approved and has accordingly recorded a reserve of $7.6 million.

Filings with the PUCT and Texas Cities. In March 1994, the Texas Office of Public Utility Counsel and certain cities served by GSU instituted an investigation of the reasonableness of GSU's rates. In June 1994, GSU provided the cities with information that GSU believed supported the current rate level. GSU filed the same information with the PUCT in June 1994, pursuant to provisions of the Merger. In September 1994, certain cities adopted ordinances directing GSU to reduce its Texas retail rates by $45.9 million. GSU appealed the cities' ordinances to the PUCT for a determination of reasonableness of GSU's rates.

In November 1994, those cities that intervened in the PUCT appeal filed testimony with the PUCT supporting a $118 million base rate reduction in lieu of the previously proposed $45.9 million reduction. In November 1994, the PUCT staff filed testimony that supported a $38.2 million base rate reduction. GSU filed information with the PUCT that it believed supported the current level of rates. Hearings were held in December 1994 and on March 20, 1995, the PUCT ordered a $72.9 million annual base rate reduction for the period March 31, 1994, through September 1, 1994, decreasing to an annual base rate reduction of $52.9 million after September 1, 1994. In accordance with the Merger agreement, the rate reduction is applied retroactively to March 31, 1994. As a result, GSU recorded a $57 million reserve for rate refund in 1994 which reduced net income after tax by $41.6 million. The rate reduction is being appealed and no assurance can be given as to the timing or outcome of the appeal.

Texas Cities Rate Settlement - 1993. In June 1993, 13 cities within GSU's Texas service area instituted an investigation to determine whether GSU's current rates were justified. In October 1993, the general counsel of the PUCT instituted an inquiry into the reasonableness of GSU's rates. In November 1993, a settlement agreement was filed with the PUCT which provided for an initial reduction in GSU's annual retail base revenues in Texas of approximately $22.5 million effective for electric usage on or after November 1, 1993, and a second reduction of $20 million effective September 1994. Pursuant to the settlement, GSU reduced rates with a $20 million one-time bill credit in December 1993, and refunded approximately $3 million to Texas retail customers on bills rendered in December 1993. The PUCT approved the settlement agreement on July 21, 1994. The cities' rate inquiries were settled earlier on the same terms.

LPSC Rate Review Order - 1994. In May 1994, GSU made the required first post-Merger earnings analysis filing with the LPSC. On December 14, 1994, the LPSC ordered a $12.7 million annual rate reduction for GSU effective January 1995. The rate order included, among other things, a reduction in GSU's Louisiana jurisdictional authorized return on equity from 12.75% to 10.95% and the amortization for the benefit of the customers of $8.3 million of previously deferred unbilled revenue, representing one-half of the total resulting from a change in accounting discussed in Note 1 of Entergy Corporation and Subsidiaries' Notes to Consolidated Financial Statements. On December 28, 1994, GSU received a preliminary injunction from the 19th Judicial District Court regarding $8.3 million of the reduction. On January 1, 1995, GSU reduced rates by $4.4 million. The entire $12.7 million reduction is being appealed and no assurance can be given as to the timing or outcome of the appeal.

LPSC Fuel Cost Review. In November 1993, the LPSC ordered a review of GSU's fuel costs for the period October 1988 through September 1991 (Phase I) based on the number of outages at River Bend and the findings in the June 1993 PUCT fuel reconciliation case. In July 1994, the LPSC ruled in the Phase I fuel review case and ordered GSU to refund approximately $27 million to its customers. Under the order, a refund of $13.1 million, which was not contested under a Louisiana Supreme Court decision as discussed below, was made through a billing credit on August 1994 bills. In August 1994, GSU appealed the remaining portion of the LPSC ordered refund to the district court. GSU has made no reserve for the remaining portion, pending outcome of the district court appeal, and no assurance can be given as to the timing or outcome of the appeal.

On January 18, 1995, GSU met with the Special Counsel of the LPSC to discuss the procedural schedule for the upcoming fuel review (Phase II). The period under investigation was determined to be from October 1991 to December 1994. Hearings are scheduled to begin in July 1995.

In February 1990, the LPSC disallowed the pass-through to ratepayers for the portion of GSU's cost to purchase power from NISCO representing the excess of NISCO's purchase price of the units over GSU's depreciated cost of the units. GSU appealed the 1990 order. In March 1994, the Louisiana Supreme Court ruled in favor of the LPSC. GSU recorded an estimated refund provision of $13.1 million, before related income taxes of $5.3 million.

Least Cost Planning. Currently, the PUCT does not have least cost planning rules in place, and GSU has not filed a Least Cost Plan with the PUCT. However, the PUCT staff has begun a rulemaking process for such rules, and GSU is actively participating in this process. GSU has not yet filed a Least Cost Plan with the LPSC. GSU intends to adopt the RIM as the screening criterion for DSM measures programs including those DSM measures targeted at strategic load growth. This criterion was adopted because programs selected under this screen will minimize the rate impact of any programs on all customers. GSU has indicated that it will not seek special rate treatment, such as rate riders, for the cost of programs or the loss of revenue due to DSM for programs selected using the RIM criterion.

Fuel Recovery. In January 1993, the PUCT adopted a new rule for setting a fixed fuel factor, which is intended to recover projected allowable fuel and purchased power costs not covered by base rates. To the extent actual costs vary from the fixed factor, the PUCT may require refunds of overcharges or permit recovery of undercharges. Under the new rule, fuel factors are to be revised every six months, and GSU is on a schedule providing for revision each March and September. The PUCT is required to act within 60 or 90 days, depending on whether or not a hearing is required, and refunds and surcharges will be required based upon a materiality threshold of 4% of Texas retail fuel revenues. Fuel charges will also be subject to reconciliation proceedings every three years, at which time additional adjustments may be required (see "*Texas Fuel Cost Review*," above). All of GSU's rate schedules in Louisiana include a fuel adjustment clause to recover the cost of fuel and purchased power energy costs. The fuel adjustment reflects the delivered cost of fuel for the second preceding month.

LP&L

LPSC Jurisdiction. In a series of LPSC orders, court decisions, and agreements from late 1985 to mid-1988, LP&L was granted rate relief with respect to costs associated with Waterford 3 and LP&L's share of capacity and energy from Grand Gulf 1, subject to certain terms and conditions. With respect to Waterford 3, LP&L was granted an increase aggregating $170.9 million over the period 1985-1988, and LP&L agreed to permanently absorb, and not recover from retail ratepayers, $284 million of its investment in the unit and to defer $266 million of its costs related to the years 1985-1988 to be recovered over approximately 8.6 years beginning in April 1988. As of December 31, 1994, LP&L's unrecovered deferral balance was $54.0 million. With respect to Grand Gulf 1, LP&L agreed to absorb, and not recover from retail ratepayers, 18% of its 14% share (approximately 2.52%) of the costs of Grand Gulf 1 capacity and energy. LP&L is allowed to recover through the fuel adjustment clause 4.6 cents per KWH (as of May 1994) for the energy related to its retained portion of these costs. Alternatively, LP&L may sell such energy to nonaffiliated parties at prices above the fuel adjustment clause recovery amount, subject to LPSC approval. (See Note 2 of LP&L's Notes to Financial Statements, "Rate and Regulatory Matters - Waterford 3 and Grand Gulf 1," for further information on LP&L's Grand Gulf 1 and Waterford 3-related rates.)

In a subsequent rate proceeding, on March 1, 1989, the LPSC issued an order providing that, in effect, LP&L was entitled to an approximately $45.9 million annual retail rate increase, but that, in lieu of a rate increase, LP&L would be permitted to retain $188.6 million of the proceeds of a 1988 settlement of litigation with a gas supplier, and to amortize such proceeds into revenues over a period of approximately 5.3 years. The amortization of the proceeds expired in mid-1994. LP&L believes that the amortization resulted in approximately the same amount of additional net income as an annual rate increase of $45.9 million would have provided over the same period. In connection with this order, LP&L agreed to a five-year base rate freeze which expired in March 1994.

Performance-Based Formula Rate Plan. In August 1994, LP&L filed a performance-based formula rate plan with the LPSC. The proposed formula rate plan would continue existing LP&L rates at current

levels, while providing financial incentive to reduce costs and maintain high levels of customer satisfaction and system reliability. A performance rating adjustment feature of the plan would allow LP&L the opportunity to earn a higher rate of return if it improves performance over time. Conversely, if performance declines, the rate of return LP&L could earn would be lowered. This provides financial incentive for LP&L to maintain continuous improvement in all three performance categories (customer price, customer satisfaction, and customer reliability). Under the proposed plan, if LP&L's earnings fall within a bandwidth around a benchmark rate of return, there would be no adjustment in rates. If LP&L's earnings are above the bandwidth, the proposed plan would automatically reduce LP&L's base rates. Alternatively, if LP&L's earnings are below the bandwidth, the proposed plan would automatically increase LP&L's base rates. The reduction or increase in base rates would be an amount representing 50% of the difference between the earned rate of return and the nearest limit of the bandwidth. In no event would the annual adjustment in rates exceed 2% of LP&L's retail revenues. Hearings were held in March 1995.

Least Cost Planning. On December 1, 1992, and July 1, 1993, LP&L filed with the LPSC and the Council the Least Cost Plan and amendments described under "Business of Entergy - Competition - *Least Cost Planning,*" above. In response to an increasingly competitive electric utility environment LP&L intends to adopt the RIM as the screening criterion for DSM programs, including those DSM measures targeted at strategic load growth. This is in place of the total resource cost test that had been used in developing the initial Least Cost Plan. This criterion was adopted because programs selected under this screen will minimize the rate impact of any programs on all customers. LP&L has indicated that it will not seek special rate treatment, such as rate riders, for the cost of programs selected using the RIM criterion. On September 28, 1994, LP&L filed a report with the Council that discussed Entergy's Least Cost Plan activities in other jurisdictions and described the motivations for these activities. LP&L also filed a motion requesting that the Council defer the filing of a new Least Cost Plan, which the existing Least Cost Plan ordinance required on December 1, 1994. On October 6, 1994, the Council approved an amendment to the City Code that rescinded the December 1, 1994 filing requirement and allowed the Council to set a future date for a new filing. The Council's actions also established that there would be a set of hearings to consider a wide range of Least Cost Plan issues, and that a new filing date would be established following these hearings. These rulings do not affect the ongoing DSM programs that LP&L is currently implementing in the City.

Regarding the activities of LP&L within the jurisdiction of the LPSC, on June 30, 1994, LP&L filed rebuttal testimony with the LPSC explaining LP&L's new direction for least cost planning. On July 18, 1994, LP&L filed a motion to withdraw its Least Cost Plan and for approval of an experimental time-of-use-rate. LP&L will file, for informational purposes only, a revised Least Cost Plan in the fourth quarter of 1995. The LPSC responded to LP&L's request by placing LP&L's application for approval in abeyance. However, the LPSC did require LP&L to file a set of proposed pilot programs. In December 1994, LP&L filed a set of proposed pilot programs with the LPSC. LP&L has agreed not to seek special treatment of the costs or loss of revenues due to DSM measures associated with these pilot programs. The LPSC has also ordered that a set of generic hearings be held to address integrated resource planning issues for all electric utilities within its jurisdiction. No procedural schedule has been issued for these proceedings.

Fuel Adjustment Clause. LP&L's rate schedules include a fuel adjustment clause to reflect the (1) delivered cost of fuel in the second preceding month and (2) purchased power energy costs. The fuel adjustment also reflects a surcharge for deferred fuel expense arising from the monthly reconciliation of actual fuel cost incurred with fuel cost revenues billed to customers. LP&L defers on its books fuel costs that will be reflected in customer billings in the future under the fuel adjustment clause.

MP&L

Rate Freeze. In a stipulation entered into by MP&L in connection with the settlement of various issues related to the Merger, MP&L agreed that (1) for a period of five years beginning on November 9, 1993, retail base rates under MP&L's formulary rate plan would not be increased above the level of rates in effect on November 1, 1993, and (2) MP&L would not request any general retail rate increase that would increase retail rates above the

level of MP&L's rates in effect as of November 1, 1993, and that would become effective in such five-year period except for, among other things, increases associated with the recovery of deferred Grand Gulf 1-related costs, recovery under the fuel adjustment clause, adjustments for certain taxes, and force majeure (defined to include, among other things, war, natural catastrophes, and high inflation).

Recovery of Grand Gulf 1 Costs. The MPSC's Final Order on Rehearing, issued in 1985, affirmed by the United States Supreme Court in 1988, and subsequently revised in 1988, granted MP&L an annual base rate increase of approximately $326.5 million in connection with its allocated share of Grand Gulf 1 costs. The Final Order on Rehearing also provided for the deferral of a portion of such costs that were incurred each year through 1992, and recovery of these deferrals over a period of six years ending in 1998. As of December 31, 1994, the uncollected balance of MP&L's deferred costs was approximately $492.3 million. MP&L is permitted to recover the carrying charges on all deferred amounts on a current basis.

Formula Rate Plan. Under a formulary incentive rate plan (Formula Rate Plan) effective March 25, 1994, MP&L's earned rate of return is calculated automatically every 12 months and compared to and adjusted against a benchmark rate of return (calculated under a separate formula within the Formula Rate Plan). The Formula Rate Plan allows for periodic small adjustments in rates based on a comparison of earned to benchmark returns and upon certain performance factors. In the same proceeding, the MPSC conducted a general review of MP&L's current rates and on March 1, 1994, issued a final order adopting the Formula Rate Plan and previously agreed-upon stipulations of (1) a required return on equity of 11% and (2) certain accounting adjustments that resulted in a 4.3% ($28.1 million) reduction in MP&L's June 30, 1993, test-year base revenues. The MPSC's order required MP&L to file rates designed to provide for this reduction in operating revenues for the test year on or before March 18, 1994, which became effective March 25, 1994. The final order was appealed to the Mississippi Supreme Court on May 17, 1994, by Mississippi Valley Gas Company (MVG) on the grounds that the MPSC issued the final order without having reviewed the cost of MP&L's promotional practices, some of which MVG alleged to be improper. MVG filed a motion to dismiss the appeal, and on October 28, 1994, the Mississippi Supreme Court granted MVG's motion.

February 1994 Ice Storm/Rate Rider In early February 1994, an ice storm left more than 80,000 MP&L customers without electric power across the service area. The storm was the most severe natural disaster ever to affect the System, causing damage to transmission and distribution lines, equipment, poles, and facilities in certain areas, primarily in Mississippi. Repair costs totaled approximately $77.2 million, with $64.6 million of these amounts capitalized as plant-related costs. The remaining balances were recorded as a deferred debit. On April 15, 1994, MP&L filed for rate recovery of costs related to the ice storm. MP&L's filing, as subsequently amended, requested recovery of the revenue requirement associated with MP&L's ice storm costs recorded through April 30, 1994, representing approximately 86% of the total estimated ice storm costs. MP&L may make another ice storm rate filing with the MPSC during 1995 to recover ice storm costs recorded by MP&L after April 30, 1994. In August 1994, MP&L and the MPSC's Public Utilities Staff entered into a stipulation with respect to the recovery of ice storm costs recorded through April 30, 1994, and in September 1994, the MPSC approved the stipulation. Under the stipulation, MP&L implemented an ice storm rider schedule, which went into effect on September 29, 1994, that will increase rates approximately $8 million annually for five years. At the end of the five-year period, the revenue requirement associated with the undepreciated ice storm capitalized costs will be included in MP&L's base rates to the extent that this revenue requirement does not result in MP&L's rate of return on rate base being above the benchmark rate of return under MP&L's formula rate plan.

Least Cost Planning. On December 1, 1992, and July 1, 1993, MP&L filed with the MPSC the Least Cost Plan described in "Business of Entergy - Competition - *Least Cost Planning*," above. In response to an increasingly competitive electric utility environment MP&L filed a motion on June 20, 1994, with the MPSC to lift a currently effective stay order and dismiss without prejudice the proposed Least Cost Plan. On July 28, 1994, the MPSC issued an order that lifted the stay and dismissed, without prejudice, the Least Cost Plan filing. MP&L will file, for informational purposes only, a revised Least Cost Plan in the fourth quarter of 1995. In this plan, MP&L intends to adopt the RIM as the screening criterion for DSM programs including

those DSM measures targeted at strategic load growth. This is in place of the total resource cost test that had been used in developing the initial Least Cost Plan. This criterion was adopted because programs selected under this screen will minimize the rate impact of any programs on all customers. MP&L has indicated that it will not seek special rate treatment, such as rate riders, for the cost of programs or loss of revenue due to DSM for programs selected using the RIM criterion.

Fuel Adjustment Clause. MP&L's rate schedules include a fuel adjustment clause that permits recovery from customers of changes in the cost of fuel and purchased power. The monthly fuel adjustment rate is based on projected sales and costs for the month, adjusted for differences between actual and estimated costs for the second prior month.

NOPSI

Recovery of Grand Gulf 1 Costs. Under NOPSI's various Rate Settlements with the Council (which include the 1986 NOPSI Settlement, the February 4 Resolution relating to prudence issues, and the 1991 NOPSI Settlement of the issues raised in the February 4 Resolution), NOPSI agreed to absorb and not recover from ratepayers a total of $186.2 million of its Grand Gulf 1 costs. NOPSI was permitted to implement annual rate increases in decreasing amounts each year through 1995, and to defer certain costs and related carrying charges, for recovery on a schedule extending from 1991 through 2001. As of December 31, 1994, the uncollected balance of NOPSI's deferred costs was $204.7 million. NOPSI also agreed to a base rate freeze through October 31, 1996, excluding the scheduled increases, certain changes in tax rates, and increases related to catastrophic events. However, this base rate freeze was amended by the 1994 NOPSI Settlement discussed below. See Note 2 of NOPSI's Notes to Financial Statements, "Rate and Regulatory Matters - Prudence Settlement and Finalized Phase-In Plan."

Electric Retail Rate Reduction. On November 18, 1993, in connection with the settlement of various issues related to the Merger, the Council adopted a resolution requiring NOPSI to reduce its annual electric base rates by $4.8 million on bills rendered on or after November 1, 1993.

1994 NOPSI Settlement. In a settlement with the Council that was approved on December 29, 1994, NOPSI agreed to reduce electric and gas rates and issue credits and refunds to customers. Effective January 1, 1995, NOPSI implemented a $31.8 million permanent reduction in electric base rates and a $3.1 million permanent reduction in gas base rates. These adjustments resolved issues associated with NOPSI's return on equity exceeding 13.76% for the test year September 30, 1994. Under the 1991 NOPSI Settlement, NOPSI recovers from its retail customers its allocable share of certain costs related to Grand Gulf 1. NOPSI's base rates to recover those costs were derived from estimates of those costs made at that time. Any overrecovery of costs is required to be returned to customers. Grand Gulf 1 experienced lower operating costs than previously estimated, and NOPSI agreed to reduce its base rates in two steps to more accurately match the current costs related to Grand Gulf 1. On January 1, 1995, NOPSI implemented a $10 million permanent reduction in base electric rates to reflect the reduced costs related to Grand Gulf 1, to be followed by an additional $4.4 million rate reduction on October 31, 1995. These Grand Gulf 1 rate reductions, which are expected to be largely offset by lower operating costs, may reduce NOPSI's after-tax net income by approximately $1.4 million per year beginning November 1, 1995. The next scheduled Grand Gulf 1 phase-in rate increase in the amount of $4.4 million on October 31, 1995, will not be affected by the 1994 NOPSI Settlement.

The 1994 NOPSI Settlement also requires NOPSI to credit its customers $25 million over a 21-month period, beginning January 1, 1995, in order to resolve disputes with the Council regarding the interpretation of the 1991 NOPSI Settlement. NOPSI reduced its revenues by $25 million and recorded a $15.4 million net-of-tax reserve associated with the credit in the fourth quarter of 1994. The 1994 NOPSI Settlement further required NOPSI to refund, in December 1994, $13.3 million of credits previously scheduled to be made to customers during the period January 1995 through July 1995. These credits were associated with a July 7, 1994, Council resolution that ordered a $24.95 million rate reduction based on NOPSI's overearnings during

the test year ended September 30, 1993. Accordingly, NOPSI recorded an $8 million net-of-tax charge in the fourth quarter of 1994.

The 1994 NOPSI Settlement also required NOPSI to refund $9.3 million of overcollections associated with Grand Gulf 1 operating costs and $10.5 million of refunds associated with the settlement by System Energy of a FERC tax audit. The settlement of the FERC tax audit by System Energy required refunds to be passed on to NOPSI and to other Entergy subsidiaries and then on to customers. These refunds have no effect on current period net income.

Gas Rates. In May 1992, NOPSI and the Council settled a pending application for gas rate increases. The settlement provided for annual rate increases of approximately $3.8 million in May 1992 and 1993, and the deferral of an additional $3 million for recovery in the years beginning in May 1993 through May 1996. NOPSI agreed to a base rate freeze, except for the scheduled increases and certain other exceptions, through October 31, 1996. However, this was amended by the 1994 NOPSI Settlement discussed above.

Least Cost Planning. On December 1, 1992, and July 1, 1993, NOPSI filed with the Council the Least Cost Plan described under "Business of Entergy - Competition - *Least Cost Planning,*" above. In response to an increasingly competitive electric utility environment NOPSI intends to adopt RIM as the screening criterion for DSM programs including those DSM measures targeted at strategic load growth. This is in place of the total resource cost test that had been used in developing the initial Least Cost Plan. This criterion was adopted because programs selected under this screen will minimize the rate impact of any programs on all customers. NOPSI has indicated that it will not seek special rate treatment, such as rate riders, for the cost of programs selected using the RIM criterion. NOPSI filed a report on September 28, 1994, with the Council that discussed Entergy's Least Cost Plan activities in other jurisdictions and described the motivations for these activities. NOPSI also filed a motion requesting that the Council defer the filing of a new Least Cost Plan, which the existing Least Cost Plan ordinance required on December 1, 1994. On October 6, 1994, the Council approved an amendment to the City Code that rescinded the December 1, 1994, filing requirement and allowed the Council to set a future date for a new filing. The Council's actions also established that there would be a set of hearings to consider a wide range of Least Cost Plan issues, and that a new filing date would be established following these hearings. These rulings do not affect the ongoing DSM programs that NOPSI is currently implementing in the City. The Council has established a proceeding to consider NOPSI's request for significant changes in the Least Cost Plan Ordinance. NOPSI's initial testimony in that matter was filed on November 17, 1994, and has been the subject of discovery requests from the Council's advisors and intervenors. Initial testimony of the Council's advisors and intervenors was filed February 10, 1995, and rebuttal testimony of all parties was due March 10, 1995.

In connection with the settlement of various issues related to the Merger, the Council adopted a resolution on November 18, 1993, that provides that the Council will not disallow the first $3.5 million of costs incurred by NOPSI through October 31, 1993, in connection with the Least Cost Plan.

Fuel Adjustment Clause. NOPSI's electric rate schedules include a fuel adjustment clause to reflect the delivered cost of fuel in the second preceding month, adjusted by a surcharge for deferred fuel expense arising from the monthly reconciliation of actual fuel cost incurred with fuel cost revenues billed to customers. The adjustment clause, on a monthly basis, also reflects the difference between nonfuel Grand Gulf 1 costs paid by NOPSI and the estimate of such costs provided in NOPSI's Grand Gulf 1 Rate Settlements. NOPSI's gas rate schedules include a gas cost adjustment to reflect gas costs in excess of those collected in rates, adjusted by a surcharge similar to that included in the electric adjustment clause. NOPSI defers on its books fuel and purchased gas costs to be reflected in billings to customers in the future under the fuel adjustment clause.

REGULATION

Federal Regulation

Holding Company Act. Entergy Corporation is a public utility holding company registered under the Holding Company Act. As such, Entergy Corporation and its various direct and indirect subsidiaries (with the exception of its independent power/EWG subsidiaries) are subject to the broad regulatory provisions of that Act. Except with respect to investments in certain EWG projects and foreign utility company projects (see "Business of Entergy - Competition - *General,*" above for a discussion of the EPAct), Section 11(b)(1) of the Holding Company Act limits the operations of a registered holding company system to a single, integrated public utility system, plus additional systems and businesses as provided by that section.

Entergy Corporation, along with ten other electric utility holding companies, recently asked Congress to repeal the Holding Company Act. The Holding Company Act requires oversight by the SEC of many business practices and activities of utility holding companies and their subsidiaries including, among other things, nonutility activities. Entergy Corporation believes that the Holding Company Act inhibits its ability to compete in the evolving electric energy marketplace, and largely duplicates the oversight activities already performed by FERC and state and local public service commissions.

Federal Power Act. The System operating companies, System Energy, and Entergy Power are subject to the Federal Power Act as administered by FERC and the DOE. The Federal Power Act provides for regulatory jurisdiction over the licensing of certain hydroelectric projects, the business of, and facilities for, the transmission and sale at wholesale of electric energy in interstate commerce and certain other activities of the System operating companies, System Energy, and Entergy Power as interstate electric utilities, including accounting policies and practices. Such regulation includes jurisdiction over the rates charged by System Energy for capacity and energy provided to AP&L, LP&L, MP&L, and NOPSI, or others, from Grand Gulf 1.

AP&L holds a license for two hydroelectric projects (70 MW) that was renewed on July 2, 1980. This license, granted by FERC, will expire in February 2003.

Regulation of the Nuclear Power Industry

General. Under the Atomic Energy Act of 1954 and the Energy Reorganization Act of 1974, operation of nuclear plants is intensively regulated by the NRC, which has broad power to impose licensing and safety-related requirements. In the event of non-compliance, the NRC has the authority to impose fines or shut down a unit, or both, depending upon its assessment of the severity of the situation, until compliance is achieved. AP&L, GSU, LP&L, and System Energy, as owners of all or a portion of ANO, River Bend, Waterford 3, and Grand Gulf 1, respectively, and Entergy Operations, as the operator of these units, are subject to the jurisdiction of the NRC. Revised safety requirements promulgated by the NRC have, in the past, necessitated substantial capital expenditures at System nuclear plants and additional such expenditures could be required in the future.

The nuclear power industry faces uncertainties with respect to the cost and availability of long-term arrangements for disposal of spent nuclear fuel and other radioactive waste, nuclear plant operational issues, the technological and financial aspects of decommissioning plants at the end of their licensed lives, and the effect of certain requirements relating to nuclear insurance. These matters are briefly discussed below.

Spent Fuel and Other High-Level Radioactive Waste. Under the Nuclear Waste Policy Act of 1982, the DOE is required, for a specified fee, to construct storage facilities for, and to dispose of, all spent nuclear fuel and other high-level radioactive waste generated by domestic nuclear power reactors. The NRC, pursuant to this Act, also requires operators of nuclear power reactors to enter into spent fuel disposal contracts with the DOE, and the affected System companies have entered into such disposal contracts. However, the DOE has not yet identified a permanent storage repository and, as a result, future expenditures may be required to increase spent fuel storage capacity at the plant sites. Currently the DOE projects it will begin to accept spent fuel no earlier than 2010. In

the meantime, all System companies are responsible for spent fuel storage. (For further information concerning spent fuel disposal contracts with the DOE, schedules for initial shipments of spent nuclear fuel, current on-site storage capacity, and costs of providing additional on-site storage capacity, see Note 8 of AP&L's, GSU's, and LP&L's, and Note 7 of System Energy's, Notes to Financial Statements, "Commitments and Contingencies - Spent Nuclear Fuel and Decommissioning Costs.")

Low-Level Radioactive Waste. The availability and cost of disposal facilities for low-level radioactive waste resulting from normal operation of nuclear units are subject to a number of uncertainties. Under the Low-Level Radioactive Waste Policy Act of 1980, as amended, each state is responsible for disposal of its own waste, and states may join in regional compacts to jointly fulfill their responsibilities. The States of Arkansas and Louisiana participate in the Central States Compact, and the State of Mississippi participates in the Southeast Compact. Two disposal sites are currently operating in the United States, and one of them, which is located in Washington, is closed to out-of-region generators. The second site, the Barnwell Disposal Facility (Barnwell) located in South Carolina, is operated by the Southeast Compact and the State of Mississippi is expected to have access to this site through December 1995. Barnwell had been open to out-of-region generators (including generators in Arkansas and Louisiana) in the past; however, on April 14, 1993, the Southeast Compact voted to deny access to Barnwell to members of the Central States Compact. Such access was reinstated for the period from October 1993 through June 1994, at which time legislative action by the State of South Carolina was required to permit further access to out-of-region generators. The South Carolina legislature failed to take action to permit further access to out-of-region generators; therefore, since July 1994, low-level radioactive waste generators in the Central States Compact, including AP&L, GSU, and LP&L, have been required to store such waste on-site until a Central States Compact facility becomes operational or another site becomes accessible.

Both the Central States Compact and the Southeast Compact are working to establish additional disposal sites. The System, along with other waste generators, funds the development costs for new disposal facilities. The System's expenditures to date are approximately $30 million; and future levels of expenditures cannot be predicted. Until such facilities are established, the System will continue to seek access to existing facilities, which may be available at costs that are higher than those incurred in the past, or which may be unavailable. If such access is unavailable, the System will store low-level waste on-site at the affected units.

Decommissioning. AP&L, GSU, LP&L, and System Energy are recovering portions of their estimated decommissioning costs for ANO, River Bend, Waterford 3, and Grand Gulf 1, respectively. These amounts are being deposited in external trust funds that, together with the earnings thereon, can only be used for future decommissioning costs. Estimated decommissioning costs are regularly reviewed and updated to reflect inflation and changes in regulatory requirements and technology, and applications will be made to appropriate regulatory authorities to reflect in rates any future changes in projected decommissioning costs. (For additional information with respect to decommissioning costs for ANO, River Bend, Waterford 3, and Grand Gulf 1, respectively, see Note 8 of AP&L's, GSU's, and LP&L's and Note 7 of System Energy's Notes to Financial Statements, "Commitments and Contingencies - Spent Nuclear Fuel and Decommissioning Costs.")

Uranium Enrichment Decontamination and Decommissioning Fees. The EPAct requires all electric utilities (including AP&L, GSU, LP&L, and System Energy) that have purchased uranium enrichment services from the DOE to contribute up to a total of $150 million annually, adjusted for inflation, up to a total of $2.25 billion over approximately 15 years, for decommissioning and decontamination of enrichment facilities. AP&L's, GSU's, LP&L's, and System Energy's estimated annual contributions to this fund are approximately $3.4 million, $0.9 million, $1.3 million, and $1.4 million, respectively, in 1995 dollars over approximately 15 years. Contributions to this fund are to be recovered through rates in the same manner as other fuel costs.

Nuclear Insurance. The Price-Anderson Act limits public liability for a single nuclear incident to approximately $8.92 billion as of December 31, 1994. AP&L, GSU, LP&L, and System Energy have protection with respect to this liability through a combination of private insurance (currently $200 million each) and an industry assessment program, and also have insurance for property damage, costs of replacement power, and other risks relating to nuclear generating units. (For a discussion of insurance applicable to nuclear programs of AP&L,

GSU, LP&L, and System Energy, see Note 7 of System Energy's and Note 8 of AP&L's, GSU's, and LP&L's Notes to Financial Statements, and Note 8 of Entergy Corporation and Subsidiaries, Notes to Consolidated Financial Statements, "Commitments and Contingencies - Nuclear Insurance.")

Nuclear Operations

General. Entergy Operations operates ANO, River Bend, Waterford 3, and Grand Gulf 1, subject to the owner oversight of AP&L, GSU, LP&L, and System Energy, respectively. AP&L, GSU, LP&L, and System Energy, and the other Grand Gulf 1 and River Bend co-owners, have retained their ownership interests in their respective nuclear generating units. AP&L, GSU, LP&L, and System Energy have also retained their associated capacity and energy entitlements, and pay directly or reimburse Entergy Operations at cost for its operation of the units.

On June 24, 1992, the NRC issued a bulletin requiring all utilities using a certain fire barrier material in a nuclear power plant to take certain actions related to the material. This material may have been used in as many as 87 nuclear plants in the United States, including ANO, River Bend, Waterford 3, and Grand Gulf 1 (see "*River Bend,*" below for additional information).

ANO. ANO 2 experienced a forced outage for repair of certain steam generator tubes in March 1992. Further inspections and repairs were conducted at subsequent refueling and mid-cycle outages in September 1992, May 1993, April 1994, and January 1995. AP&L's budgeted maintenance expenditures were adequate to cover the cost of such repairs. Unit 2's output has been reduced 15 megawatts or 1.6% due to secondary side fouling, tube plugging, and reduction of primary temperature. Entergy Operations continues to take steps at ANO 2 to reduce the number and severity of future tube cracks. In addition, Entergy Operations continues to meet with the NRC to discuss such steps and results of inspections of the steam generator tubes, as well as the timing of future inspections. Additional inspections are planned for the normal refueling outage scheduled for October 1995.

On January 13, 1993, in connection with the Merger, GSU filed two applications with the NRC to amend the River Bend operating license. The applications sought the NRC's consent to the Merger and to a change in the licensed operator of the facility from GSU to Entergy Operations. On August 6, 1993, Cajun filed a petition to intervene and a request for a hearing in the proceedings. On January 27, 1994, the presiding NRC Atomic Safety and Licensing Board (ASLB) issued an order granting Cajun's petition to intervene and ordered a hearing on one of Cajun's contentions. On February 15, 1994, GSU filed an appeal of the ASLB Order with the NRC. On December 16, 1993, prior to this ASLB ruling, the NRC Staff issued the two license amendments for River Bend, making them effective immediately upon consummation of the Merger. On February 14, 1994, Cajun filed with the D.C. Circuit petitions for review of the two license amendments issued by the NRC. These two amendments are in full force and effect, but are subject to the outcome of the two proceedings. On August 23, 1994, the NRC issued an order disallowing GSU's appeal in the ASLB proceeding and upholding the ASLB's January 27, 1994 order. A hearing on the proceeding before the ASLB is scheduled to begin May 9, 1995.

State Regulation

General. Each of the System operating companies is subject to regulation by its respective state and/or local regulatory authorities with jurisdiction over the service areas in which each company operates. Such regulation includes authority to set rates for electric and gas service provided at retail. (See "Rate Matters and Regulation - Rate Matters - Retail Rate Matters," above.)

AP&L is subject to regulation by the APSC and the Tennessee Public Service Commission (TPSC). APSC regulation includes the authority to set rates, determine reasonable and adequate service, fix the value of property used and useful, require proper accounting, control leasing, control the acquisition or sale of any public utility plant or property constituting an operating unit or system, set rates of depreciation, issue certificates of convenience and necessity and certificates of environmental compatibility and public need, and control the issuance

and sale of securities. Regulation by the TPSC includes the authority to set standards of service and rates for service to customers in the state, require proper accounting, control the issuance and sale of securities, and issue certificates of convenience and necessity.

GSU is subject to the jurisdiction of the municipal authorities of incorporated cities in Texas as to retail rates and services within their boundaries, with appellate jurisdiction over such matters residing in the PUCT. GSU is also subject to regulation by the PUCT as to retail rates and services in rural areas, certification of new generating plants, and extensions of service into new areas. GSU is subject to regulation by the LPSC as to electric and gas service, rates and charges, certification of generating facilities and power or capacity purchase contracts, and other matters.

LP&L is subject to the jurisdiction of the LPSC as to rates and charges, standards of service, depreciation, accounting, and other matters, and is subject to the jurisdiction of the Council with respect to such matters within Algiers.

MP&L is subject to regulation as to service, service areas, facilities, and retail rates by the MPSC. MP&L is also subject to regulation by the APSC as to the certificate of environmental compatibility and public need for the Independence Station.

On October 11, 1994, twelve Mississippi cities filed a complaint in state court against MP&L and eight electric power associations seeking a judgment from the court declaring unconstitutional certain Mississippi statutes that establish the procedure that must be followed before a municipality can acquire the facilities and certificate rights of a utility serving in the municipality. Specifically, the suit requests that the court declare unconstitutional certain 1987 amendments to the Mississippi Public Utilities Act that require that the MPSC cancel a utility's certificate to serve in the municipality before a municipality may acquire a utility's facilities located in the municipality. The suit also requests that the court find that Mississippi municipalities can serve any consumer in the boundaries of the municipality and within one mile thereof. Such a finding would be contrary to Mississippi Supreme Court decisions that have held that a municipality cannot serve in another utility's service area even where the municipal boundaries extend into such service area. On January 6, 1995, MP&L and the other defendants filed motions to dismiss. The matter is pending and will be vigorously contested by MP&L.

NOPSI is subject to regulation as to electric and gas service, rates and charges, standards of service, depreciation, accounting, issuance of certain securities, and other matters by the Council.

Franchises. AP&L holds exclusive franchises to provide electric service in 301 incorporated cities and towns in Arkansas, all of which are unlimited in duration and terminable by either party. In Arkansas, franchises are considered to be contracts and therefore are terminable upon breach of the contract.

GSU holds non-exclusive franchises, permits, or certificates of convenience and necessity to provide electric and gas service in 55 incorporated villages, cities, and towns in Louisiana and 64 incorporated cities and towns in Texas. GSU ordinarily holds 50-year franchises in Texas towns and 60-year franchises in Louisiana towns. The current terms of GSU's electric franchises will expire in the years 2007-2036 in Texas and in the years 2015-2046 in Louisiana. The natural gas franchise in the City of Baton Rouge will expire in the year 2015.

LP&L holds non-exclusive franchises to provide electric service in 116 incorporated villages, cities, and towns. Most of these franchises have 25-year terms expiring during the period 1995-2015. However, six of these municipalities have granted 60-year franchises, with the last one expiring in the year 2040. Of these franchises, none has expired to date, one is scheduled to expire as early as 1995, and 37 are scheduled to expire by year-end 2000. LP&L also supplies electric service in 353 unincorporated communities, all of which are located in parishes (counties) from which LP&L holds non-exclusive franchises to serve the areas in which the unincorporated communities are located.

MP&L has received from the MPSC certificates of public convenience and necessity to provide electric service to the areas of Mississippi that MP&L serves, which include a number of municipalities. MP&L continues to serve in such municipalities upon payment of a statutory franchise fee, regardless of whether an original municipal franchise is still in existence.

NOPSI provides electric and gas service in the City of New Orleans pursuant to city ordinances which state, among other things, that the City has a continuing option to purchase NOPSI's electric and gas utility properties.

System Energy has no franchises from any municipality or state. Its business is currently limited to wholesale sales of power.

Environmental Regulation

General. In the areas of air quality, water quality, control of toxic substances and hazardous and solid wastes, and other environmental matters, Entergy's facilities and operations are subject to regulation by various federal, state, and local authorities. Entergy considers itself to be in substantial compliance with those environmental regulations currently applicable to its facilities and operations. Entergy has incurred increased costs of construction and other increased costs in meeting environmental protection standards. Because environmental regulations are continually changing, the ultimate compliance costs to Entergy cannot be precisely estimated at any one time. However, Entergy currently estimates that its potential capital expenditures for environmental control purposes, including those discussed in "Clean Air Legislation," below, will not be material for the System as a whole.

Clean Air Legislation. The Clean Air Act Amendments of 1990 (the Act) set up three programs, acid rain for control of sulfur and nitrogen oxides (NOx), ozone nonattainment area for control of NOx and volatile organic compounds, and operating permits for administration and enforcement of these and other Clean Air Act programs.

Under the acid rain program, no additional control equipment will be required to control sulfur dioxide. Regarding sulfur dioxide emissions, the Act provides "allowances" to most Entergy generating units based upon past emission levels and operating characteristics. Each allowance is an entitlement to emit one ton of sulfur dioxide per year. Under the Act, utilities will be required to possess allowances for sulfur dioxide emissions from affected generating units. All of Entergy's generating units are classified as "Phase II" units under the Act and are therefore subject to sulfur dioxide allowance requirements beginning in the year 2000. Based on Entergy's operating history, it is considered a "clean" utility and as such has been allocated more allowances than are currently necessary for normal operations. Entergy believes that it will be able to operate its units efficiently without installing scrubbers or purchasing allowances from outside sources, and may have excess allowances available for sale to others.

In addition, Entergy has installed additional continuous emission monitoring (CEM) equipment at its base load and cycling generating units to comply with EPA regulations under the Act. Additional CEM equipment will be installed at peaking generating units in 1995 to comply with the regulations at an estimated cost of $3.0 million.

Under ozone nonattainment programs in the area served by GSU, control equipment may eventually be required for nitrogen oxide reductions due to the ozone nonattainment status of the Baton Rouge, Louisiana and Beaumont and Houston, Texas, areas. These states are studying the causes of ozone pollution in these areas and will decide during 1995 whether to require controls in these areas. If the states decide to regulate NOx, the cost of such control equipment is estimated at $16.0 million through 1997.

Under Title V of the Act, EPA promulgated operating permit regulations in 1994 that may set new operating criteria for the fossil plants relating to fuels, emissions, and equipment maintenance practices.

Entergy may also have to install additional CEM equipment as a result of these permits. The extent of the cost will be determined on a state by state basis as plants are granted permits during 1995 and 1996. Any capital and operation and maintenance costs will begin in 1996 and 1997. The authority to impose permit fees under this program has been delegated to the states by EPA and, depending on the extent of the state program and the fees imposed by each state regulatory authority, permit fees for the System could range from $1.6 to $5.0 million annually.

Entergy currently estimates that future capital costs of approximately $16.0 million for NOx control and approximately $3.0 million for CEM could be required to comply with the Act. During 1994, Entergy incurred capital costs of approximately $5.7 million for NOx control and approximately $14.7 million for CEM.

There are several other areas, such as air toxins and visibility, that will require regulatory study and rule promulgation to determine whether pollution control equipment is necessary.

Other Environmental Matters. The provisions of the Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended (Superfund), among other things, authorize the EPA and, indirectly, the states to require the generators and certain transporters of certain hazardous substances released from or at a site, and the owners or operators of such site, to clean up the site or reimburse the costs therefor. This statute has been interpreted to impose joint and several liability on responsible parties. In compliance with applicable laws and regulations in effect at the time, the System operating companies have sent waste materials to various disposal sites over the years. Also, past operating procedures and maintenance practices, which were not subject to regulation at that time, are now regulated by various environmental laws. Some of these sites have been the subject of governmental action, thereby causing one or more of the System operating companies to be involved with site cleanup activities. The System operating companies have participated to various degrees in accordance with their potential liability in these site cleanups and have, therefore, developed experience with cleanup costs. Their experience in these matters, and their judgments related thereto, are utilized by them in evaluating these sites. In addition, the System operating companies have established reserves for environmental clean-up/restoration activities.

AP&L. AP&L has received notices from time to time between 1989 and 1993, from the EPA, the Arkansas Department of Pollution Control and Ecology (ADPC&E), and others that it (among numerous others, including various utilities, municipalities and other governmental units, and major corporations) may be a PRP for cleanup costs associated with various sites in Arkansas. Most of these sites are neither owned nor operated by any System company. Contaminants at the sites include principally polychlorinated biphenyls (PCBs), lead, and other hazardous wastes. These sites and others are described below.

AP&L received notices from the EPA and ADPC&E in 1990 and 1991, identifying it as one of 30 PRPs (along with LP&L and GSU) at one Saline County site in Arkansas. The site was contaminated with PCBs and lead. AP&L actively participated with the cleanup of the site, which was completed in 1994. EPA has reviewed and accepted the site remediation and closure report. AP&L to date has expended approximately $1.0 million at the site and does not anticipate any significant additional expenditures. The EPA has discovered an additional site in Saline County that is similar to the site mentioned above and could involve many of the same PRPs. At EPA's request, AP&L voluntarily performed stabilization activities at the site. EPA has indicated that the records associated with the site are inconclusive, therefore no PRPs have been named at this time. AP&L, LP&L and GSU believe their potential liability for this site, if any, will not be material.

Reynolds Metals Company (RMC) and AP&L notified the EPA in 1989 of possible PCB contamination at two former RMC plant sites in Arkansas to which AP&L had supplied power. AP&L completed remediation at the substations serving the plant sites at a cost of $1.7 million. Additional PCB contamination was found in a portion of a drainage ditch that flows from the RMC's Patterson facility to the Ouachita River. RMC has demanded that AP&L participate in the remediation efforts with respect to the ditch. AP&L and

independent contractors engaged by AP&L conducted an investigation of the ditch contamination and the potential migration of PCBs from the electrical equipment that AP&L maintained at the plant. The investigation concluded that little, if any, of the contamination was caused by AP&L. AP&L's expenditures thus far on the ditch have been approximately $150,000. It is AP&L's understanding that RMC has spent approximately $10.0 million to complete remediation of the ditch contamination. AP&L has not received a notice from the EPA that it may be a PRP with respect to remediation costs for this site. However, RMC is seeking reimbursement of $5.0 million (50% of expenditures) from AP&L. AP&L continues to deny responsibility for any of such remediation costs and believes that its potential liability, if any, for this site will not be material.

AP&L entered into a Consent Administrative Order dated February 21, 1991, with the ADPC&E that named AP&L as a PRP for cleanup of contamination associated with the Utilities Services, Inc. state superfund site located near Rison, Arkansas. Such site was found to have soil contaminated by PCBs and pentachlorophenol (a wood preservative chemical). Also, containers and drums that contained PCBs and other hazardous substances were found at the site. AP&L's share of total remediation costs is estimated to range between $3.0 million and $5.0 million. AP&L is attempting to identify and notify other PRPs. AP&L has received assurances from the ADPC&E that it will use its enforcement authority to allocate remediation expenses among AP&L and any other PRPs that can be identified (approximately 20 have been identified to date). AP&L has performed the activities necessary to stabilize the site, which to date has cost approximately $348,000. AP&L believes that its potential liability for this site will not be material.

As a result of an internal investigation, AP&L has discovered soil contamination at two AP&L-owned sites located in Blytheville, Arkansas, and Pine Bluff, Arkansas. The contamination appears to be a result of past operating procedures that were performed prior to any applicable environmental regulation. AP&L has investigated these sites to determine the full extent of the contamination and has stabilized the sites at an aggregate cost of approximately $250,000. AP&L estimates the remediation cost for both sites to be less than $1.0 million.

GSU. GSU has been notified by the EPA that it has been designated as a PRP for the cleanup of sites on which GSU and others have, or have been alleged to have, disposed of hazardous materials. GSU is currently negotiating with the EPA and various state authorities regarding the cleanup of some of these sites. Several class action and other suits have been filed seeking relief from GSU and others for damages caused by the disposal of hazardous waste and for asbestos-related disease that allegedly occurred from exposure on GSU premises or on premises on which GSU allegedly disposed of materials (see "Other Regulation and Litigation - *GSU*," below). While the amounts at issue in the cleanup efforts and suits may be very substantial sums, management believes that its financial condition and results of operations will not be materially affected by the outcome of the clean-ups and the suits. These environmental liabilities are described below.

In 1971, GSU purchased certain property near its Sabine generating station for possible cooling water capability expansion. Although it was not known to GSU at the time of the purchase, the property was utilized by area industries in the 1950's and 1960's as an industrial waste dump. GSU sold the property in 1984. In October 1984 the abandoned waste site on the property was included on the Superfund National Priorities List (NPL) by the EPA. The EPA has indicated that it believes GSU to be a PRP for cleanup of the site based on its past ownership. GSU has advised the EPA that it does not believe that it has such responsibility. GSU has pursued negotiations with the EPA and is a member of a task force made up of other PRPs for the voluntary cleanup of the waste site. A Consent Decree has been signed by all parties. The ultimate costs for the voluntary cleanup are not known because additional wastes have been discovered at the site since the original cleanup costs were estimated, however they are expected to be at least $15.0 million. GSU has negotiated a responsible share of 2.26% of the estimated cleanup cost. Federal and state agencies are presently examining potential liabilities associated with natural resource damages. This matter is currently under negotiation with the other PRPs and the agencies. GSU does not presently believe that its ultimate responsibility with respect to this site will be material after allowance for previously reserved amounts.

In March 1993, GSU completed its cleanup activities at a site in Houston, Texas, which is included in the NPL. On September 20, 1993, GSU received formal notification from the EPA of its acceptance of the remedial activities conducted at the site. Currently, other parties are conducting cleanup activities at the site. However, these cleanup activities are unrelated to GSU's involvement at the site. Through 1994, GSU incurred cleanup costs of approximately $3.3 million. Pursuant to the Consent Decree, GSU is responsible for oversight costs incurred by the EPA. GSU has not received a reimbursement request for outstanding oversight costs, but anticipates these costs may total between $250,000 and $500,000. GSU is pursuing contribution for the cleanup costs at the site from other parties believed to be potentially responsible.

GSU is currently involved in a multi-phased remedial investigation of an abandoned manufactured gas plant (MGP) site located in Lake Charles, Louisiana. The property was the site of an MGP that is believed to have operated during the period from approximately 1916 to 1931. Coal tar, a by-product of the distillation process, was apparently routed to a portion of the property for disposal. Since GSU purchased the property in 1926, the same area has been filled with soil and used as a landfill for miscellaneous items including electrical poles, electrical equipment, and other debris. Under an Order by the Louisiana Department of Environmental Quality (LDEQ), which is currently stayed, GSU was required to investigate and, if necessary, take remedial action at the site. On February 13, 1995 the EPA published a proposed rule adding the Lake Charles site to the NPL. Another PRP has been identified and is believed to have had a role in the ownership and operation of the MGP. Negotiations with that company for joint participation and any remedial action are expected to continue. GSU currently is awaiting notification from the EPA before initiating additional cleanup negotiations or actions. While studies to determine the location of the coal tar have been conducted, the cleanup costs of the site are unknown. GSU does not presently believe that its ultimate responsibility with respect to this site will be material after allowance for previously reserved amounts.

GSU has also been advised that it has been named as a PRP, along with a number of other companies (including LP&L), for an abandoned waste oil recycling plant site in Livingston Parish, Louisiana, which is included on the NPL. Although significant remediation has been completed, additional studies are expected to continue in 1995. GSU and LP&L have been named as defendants in a class action lawsuit lodged against a group of PRPs associated with the site. (For information regarding litigation in connection with the Livingston Parish site, see "Other Regulation and Litigation - *GSU*," below.) GSU does not presently believe that its ultimate responsibility with respect to this site will be material.

GSU received notification in 1992 from the EPA of potential liability at a site located in Iota, Louisiana. This site accepted a variety of wastes, including medical and chemical wastes. In addition to GSU, over 200 parties have been named as PRPs. The EPA is continuing its investigation of the site and has notified the PRPs of the possibility of this site being linked to another site. To date, GSU has not received notification of liability with regard to the other site. GSU does not presently believe its ultimate responsibility with respect to this site will be material.

GSU, along with AP&L and LP&L, was notified in 1990 of its potential liability at a site located in Saline County, Arkansas (see "AP&L" above). GSU believes its responsibility to be de minimus at the one site where the cleanup has been completed and also at the additional site.

LP&L and NOPSI. LP&L and NOPSI have received notices from time to time between 1986 and 1993 from the EPA and/or the states of Louisiana and Mississippi that one or both of the companies may be a PRP for cleanup costs associated with disposal sites that are currently in various stages of remediation in Arkansas, Illinois, Louisiana, Mississippi, and Missouri that are neither owned nor operated by any System company.

As to one Missouri site, LP&L's and NOPSI's aggregate liability is currently estimated not to exceed $558,000. Because of the type and the large number of PRPs (over 700, including many large utilities and national and international corporations), LP&L and NOPSI do not expect liabilities in excess of this amount.

As to the two Saline County, Arkansas, sites (see "AP&L" above), LP&L (along with GSU) believes its responsibilities to be de minimus because of its limited scope of involvement and the number and nature of PRPs . LP&L received notice from the EPA in November 1992, that it (along with AP&L) was involved in the Union County, Arkansas, site. An agreement has been negotiated and settled with the EPA that determined LP&L to be a de minimus party with a total liability of approximately $28,000 (see "*AP&L*," above).

As to one Mississippi site, LP&L (along with System Energy) understands that EPA has expended approximately $740,000 for this site (three separate locations being treated administratively as one). The State of Mississippi has indicated it intends to have PRPs conduct a cleanup of the site but has not yet taken formal action. LP&L has expended $22,300 to settle with the EPA for its costs for this site and, because there are 44 PRPs for this site (including a number of major oil companies), does not expect its share of future costs to be material.

NOPSI received notice from the EPA with respect to a second Mississippi site in the fall of 1994. NOPSI has advised the EPA in connection with that site that (1) the natural gas condensate NOPSI sold in 1983 and 1984 is excluded from the definition of "hazardous waste" under Superfund and (2) NOPSI is not aware that such material was ever shipped to the site in question. NOPSI believes it is not liable with regard to the $298,000 which EPA allegedly incurred in conducting operations at the site.

With respect to the Livingston Parish, Louisiana, site (involving at least 70 PRPs, including GSU and many other large and creditworthy corporations), LP&L has found in its records no evidence of its involvement. (For information regarding litigation in connection with the Livingston Parish site, see "Other Regulation and Litigation - *LP&L*," below.) At a second Louisiana site (also included on the NPL and involving 57 PRPs, including a number of major corporations), NOPSI believes it has no liability for the site because the material it sent to the site was not a hazardous substance.

During 1994, impact assessments were conducted at a power plant owned and operated by LP&L. Initial groundwater information is being collected for submittal to LDEQ. Remediation strategies will be formulated to restore the area to acceptable conditions. LP&L estimates costs to be approximately $135,000.

From 1992 to 1994, LP&L performed site assessments and remedial activities at two retired power plants previously owned and operated by two Louisiana municipalities. LP&L purchased the power plants, as part of the acquisition of municipal electric systems after operating them for the last few years of their useful lives. The assessments indicated some subsurface contamination from fuel oil. LP&L has completed all remediation work to the LDEQ's satisfaction for these two former generating plants, and follow-up sampling has been completed at one site. Sampling at the other site is expected to be completed in 1996. Because of LDEQ solid waste regulations promulgated in 1993, LP&L in 1994 began to close a surface impoundment at another municipal plant site now owned and operated by LP&L. With regard to hydrocarbons found in some ground water near the impoundment, additional assessment activities pursuant to LDEQ review were completed in January 1995. A report on such activities was filed with the LDEQ in February 1995.

During 1993, the LDEQ issued new rules for solid waste regulation, including waste water impoundments. LP&L has determined that certain of its power plant waste water impoundments are affected by these regulations and has chosen to either upgrade or close them. The aggregate cost of the upgrades and closures, to be completed by 1996, is estimated to be $16 million.

System Energy. In February 1990, System Energy received an EPA notice that it may be a PRP along with numerous other parties for cleanup costs associated with the same site in Mississippi in which LP&L is involved. Potential liability is based on the alleged shipment of waste oil to the site from 1981 to 1985. System Energy does not expect its share of the total expenditures to be material because there are 44 PRPs for this site, including a number of major oil companies.

Other Regulation and Litigation

Entergy Corporation and GSU. In July and August 1992, Entergy Corporation and GSU filed applications with FERC, the LPSC, and the PUCT, and Entergy Corporation, Entergy Operations, and Entergy Services filed an application with the SEC under the Holding Company Act, seeking authorization of various aspects of the Merger. In January 1993, GSU filed two applications with the NRC seeking approval of the change in ownership of GSU and an amendment to the operating license for River Bend to reflect its operation by Entergy Operations. All regulatory approvals were obtained in 1993 and the Merger was consummated on December 31, 1993, (see "Business of Entergy - Entergy Corporation-GSU Merger," above, for further information).

FERC's December 15, 1993, and May 17, 1994, orders approving the Merger were appealed to the United States Court of Appeals for the District of Columbia Circuit by Entergy Services, the City, the Arkansas Electric Energy Consumers (AEEC), the APSC, Cajun, the MPSC, the American Forest and Paper Association, the State of Mississippi, the Cities of Benton and others, and Occidental Chemical Corporation (Occidental). Entergy seeks review of FERC's deletion of a 40% cap on the amount of fuel savings GSU may be required to transfer to other Entergy operating companies under a tracking mechanism designed to protect the other companies from certain unexpected increases in fuel costs. The other parties are seeking to overturn FERC's decisions on various grounds, including the issues of whether FERC appropriately conditioned the Merger to protect various interested parties from alleged harm and FERC's reliance on Entergy's transmission tariff to mitigate any potential anticompetitive impacts of the Merger.

On November 18, 1994, the D. C. Circuit denied motions filed by Cajun, Occidental, and AEEC for a remand to FERC and a partial summary grant of the petitions for review. At the same time, the D.C. Circuit ordered that the cases be held in abeyance pending FERC's issuance of (1) a final order on remand in the proceedings on Entergy's transmission tariff, citing its July 12, 1994, opinion discussed in "Rate Matters and Regulation - Rate Matters - Wholesale Rate Matters - *Open Access Transmission*," and (2) a final order on competition issues in the proceedings on the Merger.

On December 30, 1993, Entergy Services submitted to FERC tariff revisions to comply with FERC's December 15, 1993, order approving the Merger. On February 4, 1994, the APSC and AEEC filed with FERC a joint protest to the compliance filing. They alleged that Entergy must insulate the ratepayers of AP&L, LP&L, MP&L, and NOPSI from all litigation liabilities related to GSU's River Bend nuclear facility. In its May 17, 1994, order on rehearing, FERC addressed Entergy's commitment to insulate the customers of AP&L, LP&L, MP&L, and NOPSI against liability resulting from certain litigation involving River Bend. In response to FERC's clarification of Entergy's commitment, Entergy Services filed a compliance filing on June 16, 1994, which amended certain System Agreement language submitted with the December 30, 1993, filing. APSC and AEEC subsequently filed protests questioning the adequacy of Entergy's June 16, 1994, compliance filing. Entergy filed an answer to the protest reiterating its full compliance with the requirements of FERC's May 17, 1994, order on rehearing. FERC has not yet acted on the compliance filings.

On February 14, 1994, Cajun filed with the D. C. Circuit petitions for review of the NRC's issuance of two Merger-related license amendments for River Bend. The D. C. Circuit consolidated the cases and assigned the cases to be heard by the same panel and on the same day as the petitions to review the SEC Merger-related orders. On December 29, 1994, the D. C. Circuit, citing its July 12, 1994, opinion discussed in "Rate Matters and Regulation - Rate Matters - Wholesale Rate Matters - *Open Access Transmission*," ordered the parties to file motions governing further proceedings within thirty days. Subsequently, the NRC and Entergy requested that the D. C. Circuit hold the case in abeyance; Cajun asked the D. C. Circuit to remand the proceedings to the NRC. On March 14, 1995, the D.C. Circuit denied the NRC's and Entergy's request, ordered the original NRC order be set aside, and remanded the case to the NRC for further consideration.

Requests for rehearing of the SEC order were filed with the SEC by Houston Industries Incorporated and Houston Lighting & Power Company on December 28, 1993, and petitions for review seeking to set aside the SEC order were filed with the D.C. Circuit by these parties on February 15, 1994, and by Cajun on February 14, 1994.

The matter has been remanded by the D.C. Circuit to the SEC for further consideration in light of developments at FERC relating to Entergy's transmission tariffs.

See "Nuclear Operations - *River Bend*," above for information on challenges to the NRC's approval of GSU's applications.

Appeals seeking to set aside the LPSC order related to the Merger were filed in the 19th Judicial District Court for the Parish of East Baton Rouge, Louisiana, by Houston Lighting & Power Company on August 13, 1993, and by the Alliance for Affordable Energy, Inc. on August 20, 1993. Subsequently, on February 9, 1994, Houston Lighting & Power Company filed a motion voluntarily dismissing its appeal. On February 9, 1995, the 19th Judicial District Court ruled that there was no duty on the part of the LPSC to consider environmental issues in this matter and, accordingly, dismissed the claim of the Alliance based on those grounds. The Alliance appealed this ruling to the Louisiana Supreme Court. The matter is pending.

AP&L. Three lawsuits (which have been consolidated) were filed in the Arkansas District Court by numerous plaintiffs against AP&L and Entergy Services in connection with the operation of two dams during a period of heavy rainfall and flooding in May 1990. The consolidated lawsuits sought approximately $14.4 million in property losses and other compensatory damages, and $500 million in punitive damages. In their responses to these complaints, AP&L and Entergy Services asserted, among other things, that AP&L owns flowage easements giving it the permanent right to inundate the lands owned or occupied by the plaintiffs in connection with the operation of the dams. In June 1991, the Arkansas District Court granted summary judgment to AP&L with respect to the enforceability of its flowage easements. In November 1991, the Arkansas District Court ruled that Entergy Services was entitled to the benefit of AP&L's flowage easements, in effect, removing from consideration damages in the approximate amount of $13.5 million alleged to have occurred within the areas covered by the easements. As a result, over 300 plaintiffs claiming damage within the easements were dismissed from the consolidated case in December 1991. Certain plaintiffs appealed these orders to the Eighth Circuit, which appeal was denied in March 1992. Following the Eighth Circuit's denial of their interlocutory appeal from the Arkansas District Court's orders, certain of the plaintiffs, without prejudice to their right to refile, voluntarily dismissed their claims which had not been disposed of in the Arkansas District Court's orders, thus making the orders a final adjudication, and appealed these orders to the Eighth Circuit. The remaining plaintiffs obtained a stay and an administrative termination of their claims, pending the outcome of the appeal. In December 1993, a three-judge panel of the Eighth Circuit filed its opinion affirming the judgment of the Arkansas District Court and entered judgment accordingly. The plaintiffs appealing the Arkansas District Court's orders filed petitions with the Eighth Circuit for a rehearing by the entire Court sitting en banc, which petitions were denied. These plaintiffs failed timely to petition the U.S. Supreme Court to issue a writ of certiorari to permit its review of the Eighth Circuit's decision, thereby concluding this aspect of the litigation. On February 10, 1995, the plaintiffs who had voluntarily dismissed their claims, and as to whom the flowage easements did not apply, petitioned the Arkansas District Court to reopen the proceedings as to their claims. AP&L and Entergy Services will respond to the petition by opposing the reopening of this aspect of the litigation on the basis that the applicable statutes of limitation were not tolled by the order permitting the voluntary dismissal of the claims and that the delay since final resolution of the appeals is unreasonable.

GSU. Between 1986 and 1993, GSU and approximately 70 other defendants, including many national and international corporations, including LP&L, have been sued in 17 suits in the Livingston Parish, Louisiana District Court (State District Court) by a number of plaintiffs who allegedly suffered damage or injury, or are survivors of persons who allegedly died, as a result of exposure to "hazardous toxic waste" that emanated from a site in Livingston Parish. The plaintiffs alleged that the defendants generated, transported, or participated in the storage of such wastes at the facility, which was previously operated as a waste oil recycling facility. These State District Court suits, which seek damages in total amounts ranging from $1.0 million to $10.0 billion and are now consolidated in a class action, and three federal suits in three states other than Louisiana involving issues arising from the same facility, have been removed and transferred, respectively, to the U.S. District Court for the Middle District of Louisiana (Federal District Court). On June 23, 1994, the Federal District Court entered into the record its first case management and scheduling order, which order, among other things, set the trial in this

matter for September 3, 1996. Such order also stated the intention of the Federal District Court to facilitate, prior to the scheduled trial date, appellate review of any significant decisions. At an April 28, 1994 status conference, the Federal District Court judge stated that he intended to adopt the Federal magistrate's recommendation that the class action not be remanded to the State District Court. On January 26, 1995, the Federal District Court certified the plaintiffs' lawsuit as a Federal class action. A trial date of April 11, 1994, previously set by the State District Court was not met. The matter is pending.

In October 1989, an amended lawsuit petition was filed on behalf of 985 plaintiffs in the District Court of Jefferson County, Texas, 60th Judicial District in Beaumont, Texas, naming 55 defendants including GSU. In February 1990, another amended lawsuit petition was filed in a different state District Court in Jefferson County, Texas, on behalf of over 200 plaintiffs (subsequently amended to include a total of 660) naming 127 defendants, including GSU. Possibly 300 to 400 or more of the plaintiffs in Texas may have worked at GSU's premises. Two similar suits also have been filed in the District Courts of Jefferson County, Texas, one on behalf of approximately 210 plaintiffs against about 122 defendants, including GSU, and the other on behalf of about 136 plaintiffs against approximately 63 defendants, including GSU. In these two suits together, possibly 60 to 70 plaintiffs may have worked at GSU. These two suits have not been settled. At least five other individual suits have been filed in Beaumont against GSU and others, seeking damages for alleged asbestos exposure. All of the plaintiffs in such suits are also suing GSU and all other defendants on a conspiracy count. There are 25 asbestos-related law suits filed in the 14th Judicial District Court of Calcasieu Parish in Lake Charles, Louisiana, on behalf of an aggregate of 53 plaintiffs naming from 16 to 24 defendants including GSU, and GSU is aware of as many as 61 additional cases that may be filed. The suits allege that each plaintiff contracted an asbestos-related disease from exposure to asbestos insulation products on the premises of such defendants. Settlements of the two largest of the Jefferson County suits (involving about 1660 groups of claimants) and all of the suits in Calcasieu Parish were consummated in the second and third quarters of 1994. GSU was named as one of a number of defendants in nearly all of the suits. GSU's share of the settlements was not material to its financial position or results of operations.

On February 3, 1984, Dow Chemical Company filed a request with the LPSC for a hearing to consider issues related to the purchase of cogenerated power by GSU. Other industries subsequently filed similar requests and the matters were consolidated. In November 1984, the LPSC completed hearings on rules, policies, and pricing methodologies applicable to cogeneration. Key issues were whether or not (1) GSU should be required to pay the industries for avoided capacity costs, and (2) GSU should be required to wheel power to or from the industrial plants. Although the matter is still pending before the LPSC, the LPSC did set interim rates, subject to refund by either Dow or GSU, which exclude capacity costs.

GSU/Cajun - GSU has significant business relationships with Cajun, including co-ownership of River Bend and Big Cajun 2, Unit 3. GSU and Cajun own 70% and 30% undivided interests in River Bend, respectively, and 42% and 58% undivided interests in Big Cajun 2, Unit 3, respectively.

Cajun/River Bend Litigation - In June 1989, Cajun filed a civil action against GSU in the United States District Court for the Middle District of Louisiana (District Court). Cajun's complaint seeks to annul, rescind, terminate, and/or dissolve the Joint Ownership Participation and Operating Agreement entered into on August 28, 1979 (Operating Agreement) relating to River Bend. Cajun alleges fraud and error by GSU, breach of its fiduciary duties owed to Cajun, and/or GSU's repudiation, renunciation, abandonment, or dissolution of its core obligations under the Operating Agreement, as well as the lack or failure of cause and/or consideration for Cajun's performance under the Operating Agreement. The suit also seeks to recover Cajun's alleged $1.6 billion investment in the unit as damages, plus attorneys' fees, interest, and costs. On November 25, 1992, Dixie Electric Membership Corporation and Southwest Louisiana Electric Membership Corporation, both members of Cajun, filed suit in the U.S. District Court for the Western District of Louisiana seeking a declaration that the Operating Agreement between GSU and Cajun is void because an allegedly required approval of the LPSC had not been obtained. This suit was transferred from the Western District to the Middle District. GSU believes the suits are without merit and is contesting them vigorously.

A trial without jury on the portion of the suit by Cajun to rescind the Operating Agreement which began in April 1994 has been completed, and an order from the District Court is pending. No assurance can be given as to the outcome of this litigation. If GSU were ultimately unsuccessful in this litigation and were required to make substantial payments, GSU would probably be unable to make such payments and would probably have to seek relief from its creditors under the United States Bankruptcy Code. If GSU prevails in this litigation, there can be no assurance that the United States Bankruptcy Court will allow funding of all required costs of Cajun's ownership in River Bend.

Since 1992 Cajun has not paid its full share of operating and maintenance expenses and other costs for repairs and improvements to River Bend. In addition, certain costs and expenses paid by Cajun were paid under protest. These actions were taken by Cajun based on its contention, which GSU disagrees, that River Bend's operating and maintenance expenses were excessive.

In a letter dated October 21, 1994, and at a subsequent meeting, Cajun representatives advised Entergy Corporation and GSU that, on October 25, 1994, Cajun would exhaust its 1994 budget for operating and maintenance expenses for River Bend, and did not make any further payments to GSU in 1994 for River Bend operating, maintenance or capital costs. Cajun also advised that the RUS (which provided funding to Cajun for its investment in River Bend) would not permit Cajun to budget funds in 1995 to pay its share of operating and maintenance expenses or capital costs for River Bend. However, Cajun stated that it would continue to fund its share of the nuclear decommissioning trust payments for River Bend, as well as insurance and safety-related expenses. The unpaid portion of Cajun's River Bend operating, maintenance, and capital costs for 1994 was approximately $22.4 million. Cajun's total share of River Bend annual operating (including nuclear fuel) and maintenance expenses and capital costs was approximately $76.1 million in 1994.

In view of Cajun's stated expectation that it will fund only a limited portion of its share of River Bend related operating, maintenance, and capital costs, GSU notified Cajun that it would (i) credit GSU's share of expenses for Big Cajun 2, Unit 3 against amounts due from Cajun to GSU and (ii) seek to market Cajun's share of the power from River Bend and apply the proceeds to the amounts due from Cajun to GSU. On November 2, 1994, Cajun discontinued GSU's entitlement of energy from Big Cajun 2, Unit 3. In response, on November 3, 1994, GSU filed pleadings in District Court seeking an order requiring Cajun to provide GSU with the energy from Big Cajun 2, Unit 3 to which GSU is entitled, and holding that GSU is entitled to credit amounts due from GSU to Cajun for Big Cajun 2, Unit 3 against amounts due from Cajun to GSU with respect to River Bend. On December 19, 1994, the District Court issued an injunction prohibiting Cajun from denying its share of energy from Big Cajun 2, Unit 3 and stipulating that GSU must make payments for its portion of expenses for Big Cajun 2, Unit 3 to the registry of the District Court.

Cajun Bankruptcy Filing - On December 14, 1994, the LPSC ordered Cajun to decrease the rates charged to its member distribution cooperatives by approximately $30 million per year. The rate decrease is associated with the LPSC's prior finding of imprudence in Cajun's participation in River Bend.

On December 21, 1994, Cajun filed a petition in the United States Bankruptcy Court for the Middle District of Louisiana seeking bankruptcy relief under Chapter 11 of the United States Bankruptcy Code. Cajun's bankruptcy could have a material adverse effect on GSU, including the possibility of an NRC action with respect to the operation of River Bend. However, GSU is taking appropriate steps to protect its interests and its claims against Cajun arising from the co-ownership in River Bend and Big Cajun 2, Unit 3. On December 31, 1994, the District Court issued an order lifting an automatic stay as to certain proceedings, with the result that the preliminary injunction granted by the Court on December 19, 1994, remains in effect. Cajun filed a Notice of Appeal on January 18, 1995, to the United States Court of Appeals for the Fifth Circuit seeking a reversal of the District Court's grant of the preliminary injunction. No hearing date has been set on Cajun's appeal.

In the bankruptcy proceedings, Cajun filed on January 10, 1995, a motion to reject the Operating Agreement as a burdensome executory contract. GSU responded on January 10, 1995, with a memorandum

opposing Cajun's motion filed with the District Court. This memorandum argues that the motion should be denied because (1) the Operating Agreement is not an executory contract that can be rejected under the United States Bankruptcy Code, but an agreement establishing property rights and obligations; (2) Cajun legally cannot have its payment obligations under the Operating Agreement suspended while retaining the benefits from co-ownership in River Bend, as the benefits and obligations are indivisible; (3) Cajun cannot seek to dispose of its property interest in River Bend or reject the Operating Agreement with respect thereto without disposing of all of its property interests and rejecting all of the arrangements under the River Bend package of agreements consisting of the Operating Agreement, Big Cajun 2, Unit 3 facility, certain transmission lines and the buy-back agreement pursuant to when GSU paid Cajun approximately $600 million for River Bend capacity and energy during the early years of operation of River Bend; and (4) a legal determination of Cajun's obligations and interests in River Bend should only be made as part of a plan of reorganization in bankruptcy and such determination should be subject to regulatory approvals by certain agencies with jurisdiction over Cajun, including the NRC. If the court were to grant Cajun's motion to reject the Operating Agreement, Cajun would be relieved of its financial obligations under the contract, while GSU would likely have a substantial damage claim arising from any such rejection. Although GSU believes that Cajun's motion to reject the Operating Agreement is non-meritorious, it is not possible to predict the outcome or ultimate impact of these proceedings.

During the period in which Cajun is not paying its share of River Bend costs, GSU intends to fund all costs necessary for the safe, continuing operation of the unit. The responsibilities of Entergy Operations as the licensed operator of River Bend, for safely operating and maintaining the unit are not affected by Cajun's actions.

The total resulting from Cajun's failure to fund repair projects, Cajun's funding limitation on refueling outages, and the weekly funding limitation by Cajun was $55.6 million as of December 31, 1994, compared with $33.3 million as of December 31, 1993. These amounts are reflected in long-term receivables with an offsetting reserve in other deferred credits. Cajun's bankruptcy may affect the ultimate collectibility of the amounts owed to GSU, including any amounts that may be awarded in litigation.

In September 1994, in connection with Entergy Corporation's analysis of certain preacquisition contingencies, Entergy Corporation increased its acquisition adjustment and GSU recorded a loss provision associated with the River Bend litigation between GSU and Cajun and certain underpayments by Cajun of River Bend costs, in accordance with SFAS 5, "Accounting for Contingencies." See Note 12 of Entergy Corporation's Notes to Financial Statements, "Entergy Corporation - GSU Merger" for additional information on provisions for preacquisition contingencies recorded during 1994.

Cajun/Transmission Service - GSU and Cajun are parties to FERC proceedings relating to transmission service charge disputes. In April 1992, FERC issued a final order. In May 1992, GSU and Cajun filed motions for rehearings which are pending at FERC. In June 1992, GSU filed a petition for review in the United States Court of Appeals regarding certain of the issues decided by FERC. In August 1993, the United States Court of Appeals rendered an opinion reversing the FERC order regarding the portion of such disputes relating to the calculations of certain credits and equalization charges under GSU's service schedules with Cajun. The opinion remanded the issues to FERC for further proceedings consistent with its opinion. In December 1994, FERC held a hearing to address the issues remanded by the Court of Appeals. In February 1995, FERC clarified its order, eliminating an issue that GSU believes the Court of Appeals directed FERC to reconsider.

GSU interprets the 1992 FERC order and the United States Court of Appeals' decision to mean that Cajun would owe GSU approximately $93.3 million as of December 31, 1994. However, FERC's February 1995, order indicates that FERC believes an issue, estimated by GSU to constitute approximately $26.2 million of this amount, may not be pursued by GSU in the remand proceedings. GSU further estimates that if it prevails in its May 1992 motion for rehearing, Cajun would owe GSU approximately $129.6 million as of December 31, 1994. If Cajun were to prevail in its May 1992 motion for rehearing to FERC, and if GSU

were not to prevail in its May 1992 motion for rehearing to FERC, and if FERC does not implement the court's remand as GSU contends is required, GSU estimates it would owe Cajun approximately $85.6 million as of December 31, 1994. The above amounts are exclusive of a $7.3 million payment by Cajun on December 31, 1990, which the parties agreed to apply to the disputed transmission service charges. GSU and Cajun further agreed that their positions at FERC would remain unaffected by the $7.3 million payment. Pending FERC's ruling on the May 1992 motions for rehearing, GSU has continued to bill Cajun utilizing the historical billing methodology and has booked underpaid transmission charges, including interest, in the amount of $160.2 million as of December 31, 1994. This amount is reflected in long-term receivables with an offsetting reserve in other deferred credits.

On December 7, 1993, Cajun filed a complaint in the Middle District of Louisiana alleging that GSU failed to provide Cajun an opportunity to construct certain facilities that allegedly would have reduced its rates under Service Schedule CTOC, and seeking an order compelling the conveyance of certain facilities and awarding unspecified damages. GSU has moved to dismiss the complaint on the basis, among others, that FERC has already addressed the matter in the proceedings described above.

Cajun/Service Dispute - GSU was requested by Cajun and Jefferson Davis Electric Cooperative, Inc., (Jefferson Davis) to provide transmission of power over GSU's system for delivery to the Industrial Road area near Lake Charles, Louisiana. GSU provides electric service to industrial and other customers in such area, and Cajun and Jefferson Davis do not. On October 10, 1989, Cajun filed a complaint at FERC contending that GSU wrongfully refused to provide Cajun certain transmission services so that its member, Jefferson Davis, could provide service to certain industrial customers, and it requested FERC to order GSU to provide the service. On October 26, 1989, FERC summarily dismissed Cajun's complaint, but the D.C. Circuit reversed FERC's summary determination and remanded the case to FERC for a hearing. On June 24, 1992, after a hearing, an ALJ issued an Initial Decision, again dismissing Cajun's complaint. The ALJ found that the parties' contract did not require GSU to provide the service and that Cajun's member, Jefferson Davis, had not sought permission from the LPSC to serve the end-use customers in question. If Jefferson Davis secured permission from the LPSC, the ALJ believed (but did not decide) that FERC would require GSU to provide the requested transmission service. On March 21, 1994, FERC issued an order affirming the ALJ and dismissing Cajun's complaint, finding that GSU properly exercised its contractual right to refuse to provide the service. On August 3, 1994, FERC denied rehearing. On August 12, 1994, Cajun filed a petition for review of FERC's orders in the United States Court of Appeals for the District of Columbia Circuit. The matter is pending.

Cajun and Jefferson Davis also brought a related action in federal court in the Western District of Louisiana alleging that GSU breached its obligations under the parties' contract and violated the antitrust laws by refusing to provide the transmission service described above. Cajun and Jefferson Davis seek an injunction requiring GSU to provide the requested service and unspecified treble damages for GSU's refusal to provide the service. On November 9, 1989, the district court judge denied Cajun's and Jefferson Davis' motion for a preliminary injunction. On May 3, 1991, the judge stayed the proceeding pending final resolution of the matters still pending before FERC.

Cajun River Bend Repairs - On December 2, 1991, Cajun filed a complaint seeking declaratory and injunctive relief from the U. S. District Court for the Middle District of Louisiana. The complaint concerns GSU's position that Cajun is in default with respect to paying its share of certain expenditures to repair corrosion damage in the service water system, to repair a feedwater nozzle crack, and to repair a turbine rotor. Cajun alleges that it has no obligation to pay its share of such costs and seeks a declaration that it may elect not to participate in the funding of such costs and enjoining GSU from demanding payment therefor or attempting to implement default provisions in the Operating Agreement with respect thereto. Cajun alleges that if it is required to pay its share of such costs it would be forced to default on other obligations. See "Cajun Bankruptcy Filing," above for information regarding Cajun's bankruptcy filing. GSU believes that Cajun is in default under the provisions of the Operating Agreement. No assurance can be given as to the outcome or timing of this action brought by Cajun.

Cajun Other - In May 1990, GSU received a subpoena from the Office of Inspector General - Investigations, United States Department of Agriculture, seeking production of documents relating to the construction costs of River Bend. Such office is authorized to investigate matters relating to programs of the Department of Agriculture. GSU has been sued by Cajun with respect to its participation in River Bend with funds made available through Department programs administered by the RUS. GSU has failed in its efforts to have the RUS made a party to the Cajun litigation. GSU does not know the purpose of such Office's investigation, but assumes that it relates to the Cajun civil litigation since the production of documents sought by such Office is similar to that sought by Cajun in its action against GSU. However, there can be no assurance given by GSU as to the real purpose of such Office's investigation. Among other areas of responsibility, such Office is authorized to investigate possible violations of law. GSU believes the subpoena proceeding has been administratively dismissed without prejudice to the parties.

LP&L. For information regarding litigation in connection with an abandoned waste oil recycling plant site in Livingston Parish, Louisiana, in which LP&L and GSU are defendants, see "*GSU*," above. LP&L does not believe that it was a generator of any material delivered to this facility and is defending vigorously against the claims in these suits.

Since the mid-1980's, LP&L and the tax authorities of St. Charles Parish, Louisiana (Parish), the parish in which Waterford 3 is located, have disputed use taxes paid on nuclear fuel ($4.9 million through 1989) under protest by LP&L. LP&L continues to be successful in lawsuits in the Parish with regard to recovering these taxes, plus interest, and also with regard to Parish lease tax issues pertaining to fuel financing arrangements. On the grounds of the previous favorable court decisions, LP&L continues to challenge in the courts additional use tax assessments that it has paid to the Parish and to seek additional interest that LP&L claims it is due. On October 13, 1994, Parish tax authorities sued LP&L and Entergy Corporation in the Civil District Court of Orleans Parish, Louisiana, claiming that $1.4 million of sales and use and lease taxes paid under protest by LP&L with respect to newly acquired nuclear fuel were not, in fact, paid under protest and should be disposed of by the Parish, and that unspecified additional taxes, interest, and penalties are due. Entergy Corporation was dismissed from the suit and the suit has been transferred back to the Parish where it will form part of the suit by LP&L to recover the $1.4 million of sales and use taxes it paid to the Parish under protest. Also, in early procedural stages are (1) suits by LP&L with regard to the state use tax on nuclear fuel, and (2) LP&L's defense (and indemnification, if necessary) of nuclear fuel lessors under LP&L's fuel financing arrangements in the suits filed by the Parish use tax authorities claiming approximately $64.0 million in lease and use taxes. These matters are pending.

Entergy Corporation, LP&L, and System Energy. In August 1994, Entergy received an IRS report covering the federal income tax audit of Entergy Corporation and subsidiaries for the years 1988 - 1990. The report asserts an $80 million tax deficiency for the 1990 consolidated federal income tax returns related primarily to the application of accelerated investment tax credits associated with Waterford 3 and Grand Gulf nuclear plants. Entergy Corporation believes there is no material tax deficiency and is vigorously contesting the proposed assessment.

EARNINGS RATIOS OF SYSTEM OPERATING COMPANIES AND SYSTEM ENERGY

The System operating companies and System Energy have calculated ratios of earnings to fixed charges and ratios of earnings to fixed charges and preferred dividends pursuant to Item 503 of Regulation S-K of the SEC as follows:

	Years Ended December 31,				
	1990	1991	1992	1993	1994
Ratios of Earnings to Fixed Charges(a)					
AP&L	2.16	2.25	2.28	3.11(f)	2.32
GSU	.80(g)	1.56	1.72	1.54	.36(g)
LP&L	2.32	2.40	2.79	3.06	2.91
MP&L	2.42	2.36	2.37	3.79(f)	2.12
NOPSI	2.73	5.66(e)	2.66	4.68(f)	1.91
System Energy	2.10	1.74	2.04	1.87	1.23

	Years Ended December 31,				
	1990	1991	1992	1993	1994
Ratios of Earnings to Fixed Charges and Preferred Dividends(a)(b)(c)					
AP&L	1.81	1.87	1.86	2.54(f)	1.97
GSU(d)	.59(g)	1.19	1.37	1.21	.29(g)
LP&L	1.87	1.95	2.18	2.39	2.43
MP&L	1.93	1.94	1.97	3.08(f)	1.81
NOPSI	2.36	4.97(e)	2.36	4.12(f)	1.73

(a) "Earnings" as defined by SEC Regulation S-K represent the aggregate of (1) net income, (2) taxes based on income, (3) investment tax credit adjustments-net, and (4) fixed charges. "Fixed Charges" include interest (whether expensed or capitalized), related amortization, and interest applicable to rentals charged to operating expenses.

(b) "Preferred Dividends" as defined by SEC Regulation S-K are computed by dividing the preferred dividend requirement by one hundred percent (100%) minus the income tax rate.

(c) System Energy's Amended and Restated Articles of Incorporation do not currently provide for the issuance of preferred stock.

(d) "Preferred Dividends" in the case of GSU also include dividends on preference stock.

(e) Earnings for the year ended December 31, 1991, include the $90 million effect of the 1991 NOPSI Settlement.

(f) Earnings for the year ended December 31, 1993, include approximately $81 million, $52 million, and $18 million for AP&L, MP&L, and NOPSI, respectively, related to the change in accounting principle to provide for the accrual of estimated unbilled revenues.

(g) Earnings for the year ended December 31, 1994 and 1990, for GSU were not adequate to cover fixed charges by $144.8 million and $60.6 million, respectively. Earnings for the year ended December 31, 1994 and 1990, were not adequate to cover fixed charges and preferred dividends by $197.1 million and $165.1 million, respectively.

INDUSTRY SEGMENTS

NOPSI

Narrative Description of NOPSI Industry Segments

Electric Service. NOPSI supplied electric service to 189,836 customers as of December 31, 1994. During 1994, 36% of electric operating revenues was derived from residential sales, 41% from commercial sales, 6% from industrial sales, 15% from sales to governmental and municipal customers, and 2% from sales to public utilities and other sources.

Natural Gas Service. NOPSI supplied natural gas service to 153,259 customers as of December 31, 1994. During 1994, 57% of gas operating revenues was derived from residential sales, 18% from commercial sales, 10% from industrial sales, and 15% from sales to governmental and municipal customers. (See "Fuel Supply - Natural Gas Purchased for Resale.")

Selected Financial Information Relating to Industry Segments

For selected financial information relating to NOPSI's industry segments, see NOPSI's financial statements and Note 11 of NOPSI's Notes to Financial Statements, "Business Segment Information."

Employees by Segment

NOPSI's full-time employees by industry segment as of December 31, 1994, were as follows:

Electric	527
Natural Gas	133
Total	660

(For further information with respect to NOPSI's segments, see "Property.")

GSU

For the year ended December 31, 1994, 96% of GSU's operating revenues was derived from the electric utility business. The remainder of operating revenues was derived 2% from the steam business and 2% from the natural gas business. Segment information for GSU is not provided.

Generating Stations

The total capability of the System's owned and leased generating stations as of December 31, 1994, by company and by fuel type, is indicated below:

	Owned and Leased Capability MW(1)				
Company	Total	Fossil	Nuclear	Gas Turbine and Internal Combustion	Hydro
AP&L	4,367 (2)	2,373	1,694	230 (8)	70
GSU	6,547 (2)	5,817	655 (5)	75	-
LP&L	5,405 (2)	4,311	1,075 (6)	19	-
MP&L	3,046 (2)	3,035 (4)	-	11	-
NOPSI	927 (2)	912	-	15	-
System Energy	1,028	-	1,028 (7)	-	-
Total System	21,320 (3)	16,448 (3)(4)	4,452	350	70

(1) "Owned and Leased Capability" is the dependable load carrying capability, as demonstrated under actual operating conditions based on the primary fuel (assuming no curtailments) that each station was designed to utilize.

(2) Excludes the capacity of fossil-fueled generating stations placed on extended reserve as follows: AP&L - 506 MW; GSU - 405 MW; LP&L - 157 MW; MP&L - 73 MW; and NOPSI - 143 MW. Generating stations that are not expected to be utilized in the near-term to meet load requirements are placed in extended reserve shutdown in order to minimize operating expenses.

(3) Excludes net capability of generating facilities owned by Entergy Power, which owns 809 MW of fossil-fueled capacity (see "Rate Matters and Regulation - Rate Matters - Wholesale Rate Matters - *Entergy Power*," above).

(4) Includes Independence 2, a coal unit operated by AP&L and jointly owned 25% by MP&L (210 MW), 31.5% by Entergy Power (265 MW), and the balance by various municipalities and a cooperative. The unit was out of service from August 11, 1993 to February 18, 1994, due to an explosion.

(5) GSU's nuclear capability represents its 70% undivided ownership interest in River Bend; Cajun owns the remaining 30% undivided interest.

(6) LP&L's nuclear capability represents its 90.7% undivided ownership interest and 9.3% leasehold interest in Waterford 3.

(7) System Energy's capability represents its 90% interest in Grand Gulf 1 (78.5% ownership interest and 11.5% leasehold interest). South Mississippi Electric Power Association has the remaining 10% undivided ownership interest in Grand Gulf 1. Entitlement to System Energy's capacity has been allocated to AP&L, LP&L, MP&L, and NOPSI pursuant to the Unit Power Sales Agreement.

(8) Includes 188 MW of capacity leased by AP&L through 1999.

Representatives of the System regularly review load and capacity projections in order to coordinate and recommend the location and time of installation of additional generating capacity and of interconnections in light of

the availability of power, the location of new loads, and maximum economy to the System. Based on load and capability projections and bulk power availability, the System has no current need to install additional generating capacity. To delay the need for new capacity, the System is purchasing power in the wholesale power market and engaging in conservation and DSM programs, as discussed in "Business of Entergy - Competition - *Least Cost Planning*," above. When new generation resources are needed, the System plans to meet this need with a variety of sources other than construction of new base load generating capacity. In the meantime, the System will meet capacity needs by, among other things, purchasing power in the wholesale power market and/or removing generating stations from extended reserve shutdown.

Under the terms of the System Agreement, certain generating capacity and other power resources are shared among the System operating companies. Among other things, the System Agreement provides that parties having generating capacity greater than their load requirements shall sell such capacity to those parties having deficiencies in generating capacity and that the purchasers shall pay to the sellers a charge sufficient to cover certain of the sellers' costs, including operating expenses, fixed charges on debt, dividend requirements on preferred and preference stock, and a fair rate of return on common equity investment. Under the System Agreement, these charges are based on costs associated with the sellers' steam electric generating units fueled by oil or gas. In addition, for all energy exchanged among the System operating companies under the System Agreement, the purchasers are required to pay the cost of fuel consumed in generating such energy plus a charge to cover other associated costs (see "Rate Matters and Regulation - Rate Matters - Wholesale Rate Matters - *System Agreement*," above, for a discussion of FERC proceedings relating to the System Agreement).

The System's business is subject to seasonal fluctuations, with the peak period occurring in the summer months. The System's 1994 peak demand of 18,028 MW occurred on June 28, 1994. The net System capability at the time of peak was 20,884 MW, which reflects a reduction of the System's total 21,196 MW of owned and leased capability by net off-system firm sales of 312 MW. The capacity margin at the time of the peak was approximately 13.7%, not including units placed on extended reserve and capacity owned by Entergy Power.

Interconnections

The electric power supply facilities of Entergy consist principally of steam-electric production facilities strategically located with reference to availability of fuel, protection of local loads, and other controlling economic factors. These are interconnected by a transmission system operating at various voltages up to 500 KV. Generally, with the exception of Grand Gulf 1, Entergy Power's capacity and a small portion of MP&L's capacity, operating facilities or interests therein are owned by the System operating company serving the area in which the facilities are located. However, all of the System's generating facilities are centrally dispatched. The System seeks, among other things, the lowest cost sources of energy from hour to hour. The minimum of investment and the most efficient use of plant are sought to be achieved, in part, through the coordinated scheduling of maintenance, inspection, and overhaul.

Neighboring utilities with which one or more System operating companies are directly interconnected include, Mississippi Power Company, Southwestern Electric Power Company, Southwest Power Administration, Central Louisiana Electric Company, Inc., Oklahoma Gas and Electric Company, The Empire District Electric Company, Union Electric Company, Arkansas Electric Cooperative Corporation, Tennessee Valley Authority, Cajun, Sam Rayburn Dam Electric Cooperative, Inc., SRG&T, SRMPA, Associated Electric Cooperative, Inc., Municipal Energy Agency of Mississippi, Louisiana Energy and Power Authority, Farmers Electric Cooperative, South Mississippi Electric Power Authority, and the cities of Lafayette, Plaquemine, and New Roads, Louisiana. GSU also has an interconnection agreement with Houston Lighting and Power Company providing a minor amount of emergency service only. The System operating companies also have interchange agreements with Alabama Electric Cooperative, Big Rivers Electric Cooperative, Northeast Texas Electric Cooperative, Inc., Sam Rayburn G&T Electric Cooperative, Inc., Florida Power Corporation, Florida Power & Light Company, Jacksonville Electric Authority, Oglethorpe Power Cooperative, the City of Lafayette, Louisiana, the City of Springfield, Missouri, and East Kentucky Electric Cooperative.

The System operating companies are members of the Southwest Power Pool, the primary purpose of which is to ensure the reliability and adequacy of the electric bulk power supply in the southwest region of the United States. The Southwest Power Pool is a member of the North American Electric Reliability Council. AP&L, LP&L, MP&L, and NOPSI are also members of the Western Systems Power Pool.

Gas Property

As of December 31, 1994, NOPSI distributed and transported natural gas for distribution solely within the limits of the City of New Orleans through a total of 1,419 miles of gas distribution mains and 40 miles of gas transmission lines. NOPSI receives deliveries of natural gas for distribution purposes at 14 separate locations, including deliveries from Koch Gateway Pipeline Company (formerly United Gas Pipe Line Company) at six of these locations. Of the remaining delivery points, two are principally served by interstate suppliers and the remainder are served by intrastate suppliers.

As of December 31, 1994, the gas properties of GSU were not material to GSU.

Titles

The System's generating stations are generally located on lands owned in fee simple. The greater portion of the transmission and distribution lines of the System operating companies has been constructed over lands of private owners pursuant to easements or on public highways and streets pursuant to appropriate permits. The rights of each company in the realty on which its properties are located are considered by it to be adequate for its use in the conduct of its business. Minor defects and irregularities customarily found in properties of like size and character exist, but such defects and irregularities do not materially impair the use of the properties affected thereby. The System operating companies generally have the right of eminent domain whereby they may, if necessary, perfect or secure titles to, or easements or servitudes on, privately-held lands used or to be used in their utility operations.

Substantially all the physical properties owned by each System operating company and System Energy, respectively, are subject to the lien of a mortgage and deed of trust securing the first mortgage bonds of such company. The Lewis Creek generating station is owned by GSG&T, Inc., and is not subject to the lien of the GSU mortgage securing the first mortgage bonds of GSU, but is leased and operated by GSU. In the case of LP&L, certain properties are also subject to the liens of second mortgages securing other obligations of LP&L. In the case of MP&L and NOPSI, substantially all of their properties and assets are also subject to the second mortgage lien of their respective general and refunding mortgage bond indentures.

FUEL SUPPLY

The following tabulation shows the percentages of natural gas, fuel oil, nuclear fuel, and coal used in generation, excluding that of Entergy Power, during the past three years and it also shows the average fuel cost per KWH generated by each type of fuel during that period. The balance of generation, which was immaterial, was provided by hydroelectric power.

ENTERGY

	Natural Gas		Fuel Oil		Nuclear Fuel		Coal	
Year	% of Gen	Cents per KWH	% of Gen	Cents per KWH	% of Gen	Cents Per KWH	% of Gen	Cents Per KWH
1994	44	2.24	1	3.99	39	.60	16	1.82

ENTERGY EXCLUDING GSU

	Natural Gas		Fuel Oil		Nuclear Fuel		Coal	
Year	% of Gen	Cents per KWH	% of Gen	Cents per KWH	% of Gen	Cents Per KWH	% of Gen	Cents Per KWH
1993	27	2.70	7	2.10	51	.58	15	1.91
1992	32	1.99	-	-	49	.67	18	1.90

GSU

	Natural Gas		Fuel Oil		Nuclear Fuel		Coal	
Year	% of Gen	Cents Per KWH	% of Gen	Cents Per KWH	% of Gen	Cents Per KWH	% of Gen	Cents Per KWH
1993	69	2.44	-	-	14	1.19	17	1.77
1992	76	2.01	-	-	8	1.64	16	1.68

The following tabulation shows the percentages of generation by fuel type used in generation, excluding that of Entergy Power, for 1994 (actual) and 1995 (projected). The balance of generation, which is immaterial, is provided by hydroelectric power.

	Natural Gas		Fuel Oil		Nuclear		Coal	
	1994	1995	1994	1995	1994	1995	1994	1995
System	44%	47%	1%	0%	39%	35%	16%	18%
AP&L	7	2	-	-	59	51	33	46
GSU	71	73	-	-	13	15	16	12
LP&L	57	62	-	-	43	38	-	-
MP&L	60	67	13	-	-	-	27	33
NOPSI	100	100	-	-	-	-	-	-
System Energy	-	-	-	-	100(a)	100(a)	-	-

(a) Capacity and energy from System Energy's interest in Grand Gulf 1 is allocated as follows: AP&L - 36%, LP&L - 14%, MP&L - 33%, and NOPSI - 17%.

Natural Gas

The System operating companies retain a mix of long-term firm and short-term interruptible gas contracts. Long-term firm supply contracts currently comprise less than 40% of total System requirements but can be called upon, if necessary, to satisfy a significant percentage of the System's needs. Additional gas requirements are satisfied by short-term contracts and spot-market purchases. Furthermore, in November 1992, GSU entered into a transportation service agreement with a gas supplier that obligates such supplier to provide GSU with flexible natural gas service to certain generating stations by using such supplier's pipeline and gas storage facility.

Many factors influence the availability and price of natural gas supplies for power plants including wellhead deliverability, storage and pipeline capacity, and the demand requirements of the end users. This demand is closely tied to the severity of the weather conditions in the region. Furthermore, pricing relative to other energy sources (i.e., fuel oil, coal, purchased power, etc.) will affect the demand for natural gas for power plants. Supplies of natural gas are expected to be adequate in 1995. However, pursuant to federal and state regulations, gas supplies to power plants may be interrupted during periods of shortage. To the extent natural gas supplies may be disrupted, the System operating companies will use alternate fuels, such as oil, or rely on coal and nuclear generation.

Coal

AP&L has long-term contracts for the supply of low-sulfur coal for the White Bluff Steam Electric Generating Station and the Independence Steam Electric Station (which is owned 25% by MP&L). Coal for the White Bluff Station is supplied under a contract from a mine in the State of Wyoming. The coal contract provides for the delivery of sufficient coal to operate the White Bluff Station through approximately 2002. Coal for the Independence Station is also supplied under a contract from a mine in the State of Wyoming. Coal supplied under this contract is expected to meet the requirements of the Independence Station through at least 2014. GSU has a contract for a supply of low-sulfur Wyoming coal for Nelson Unit 6, which should be sufficient to satisfy the fuel requirements at Nelson Unit 6 through 2004. Cajun has advised GSU that it has contracts that should provide an adequate supply of coal until 1997 for the operation of Big Cajun 2, Unit 3 (which is operated by Cajun and of which GSU owns a 42% undivided interest).

Nuclear Fuel

Generally, the supply of fuel for nuclear generating units involves the mining and milling of uranium ore to produce a concentrate, the conversion of uranium concentrate to uranium hexafluoride gas, enrichment of that gas, fabrication of nuclear fuel assemblies for use in fueling nuclear reactors, and disposal of the spent fuel.

System Fuels is responsible for contracts to acquire nuclear material to be used in fueling AP&L's, LP&L's, and System Energy's nuclear units and for maintaining inventories of such materials during the various stages of processing. Each of these companies currently contracts for the fabrication of its own nuclear fuel and for purchasing the required enriched uranium hexafluoride from System Fuels. The requirements for GSU's River Bend plant are covered by contracts made by GSU. System Fuels sometimes acts as agent for GSU in negotiating and/or administering such contracts.

On October 3, 1989, System Fuels entered into a revolving credit agreement with banks permitting it to borrow up to $45 million to finance its nuclear materials and services inventory. AP&L, LP&L, and System Energy agreed to purchase from System Fuels the nuclear materials and services financed under the agreement if System Fuels should default in its obligations thereunder. Such purchases would be allocated based on percentages agreed upon among the parties. In the absence of such agreement, AP&L, LP&L, and System Energy would each be obligated to purchase one-third of the nuclear materials and services.

Based upon the planned fuel cycles for the System's nuclear units, the following tabulation shows the years through which existing contracts and inventory will provide materials and services.

	Uranium Concentrate	Acquisition of or Conversion to Uranium Hexafluoride	Enrich-ment	Fabri-cation	Spent Fuel Disposal
ANO 1	(1)	(1)	(3)	1997	(4)
ANO 2	(1)	(1)	(3)	1999	(4)
River Bend	(2)	(2)	(3)	2000	(4)
Waterford 3	(1)	(1)	(3)	1999	(4)
Grand Gulf 1	(1)	(1)	(3)	2000	(4)

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(1) Current contracts will provide a significant percentage of these materials and services through termination dates ranging from 1995-1998. Additional materials and services required beyond these dates are estimated to be available for the foreseeable future.

(2) Current GSU contracts will provide a significant percentage of these materials and services for River Bend through 1996.

(3) Current contracts will provide a significant percentage of these materials and services through approximately 2000. (See "Rate Matters and Regulation - Regulation - Regulation of the Nuclear Power Industry - *Decommissioning*," above for information on annual contributions to a federal decontamination and decommissioning fund required by the EPAct to be made by AP&L, GSU, LP&L, and System Energy as a result of their enrichment contracts with the DOE.)

(4) The Nuclear Waste Policy Act of 1982 provides for the disposal of spent nuclear fuel or high level waste by the DOE. (See "Rate Matters and Regulation - Regulation - Regulation of the Nuclear Power Industry - *Spent Fuel and Other High-Level Radioactive Waste*," above for further information).

The System will enter into additional arrangements to acquire nuclear fuel beyond the dates shown above. Except as noted above, Entergy cannot predict the ultimate availability or cost of such arrangements at this time.

AP&L, GSU, LP&L, and System Energy have nuclear fuel leasing arrangements that provide for AP&L, GSU, LP&L, and System Energy to lease nuclear fuel and related equipment and services having an aggregate value of up to $125 million, $105 million, $95 million, and $105 million for each company, respectively. As of December 31, 1994, the unrecovered cost base of AP&L's, GSU's, LP&L's, and System Energy's nuclear fuel leases amounted to approximately $94.6 million, $80.0 million, $44.2 million, and $46.7 million, respectively. Each lessor finances its acquisition and ownership of nuclear fuel under a credit agreement and through the issuance of intermediate-term notes. The credit agreements, which were entered into by AP&L in 1988, by LP&L and System Energy in 1989, and by GSU in 1993, had initial terms of five years, with the exception of GSU, which has an initial term of three years. These agreements are subject to annual renewal with, in LP&L's and GSU's case, the consent of the lenders. The credit agreements for AP&L, LP&L, and System Energy have been extended and now have termination dates of December 1997, January 1998, and February 1998, respectively. The credit agreement for GSU was entered into in December 1993 and has a termination date of December 1997. The intermediate-term notes issued pursuant to these fuel lease arrangements have varying maturities through January 31, 1999. It is expected that the credit agreements will be extended, or alternative financing will be secured by each lessor, based on the particular lessee's nuclear fuel requirements. If extensions or alternative financing cannot be arranged, the lessee in each case must purchase sufficient nuclear fuel to allow the lessor to retire such borrowings.

NOPSI has several suppliers of natural gas for resale. Its system is interconnected with three interstate and three intrastate pipelines. Presently, NOPSI's primary suppliers of natural gas for resale are Koch Gas Services, Company (KGS), an interstate gas marketer, and Bridgeline and Pontchartrain, intrastate pipelines. NOPSI has a firm gas purchase contract with KGS. The KGS gas supply is transported to NOPSI pursuant to a "No-Notice" transportation service agreement with Koch Gateway Pipeline Company (KGPC). This service is subject to FERC-approved rates. NOPSI has firm contracts with its two intrastate suppliers and also makes interruptible spot market purchases when economically attractive. In recent years, natural gas deliveries have been subject primarily to weather-related curtailments. However, NOPSI has experienced no such curtailments.

After the implementation of FERC-mandated interstate pipeline restructuring, which occurred on October 31, 1993, curtailments of interstate gas supply could occur if NOPSI's suppliers failed to perform their obligations to deliver gas under their supply agreements. KGPC could curtail transportation capacity only in the event of pipeline system constraints. Based on the current supply of natural gas, and absent extreme weather related curtailments, NOPSI does not anticipate any interruptions in natural gas deliveries to its customers.

GSU purchases natural gas for resale from a single interstate supplier. Abandonment of service by the present supplier would be subject to abandonment proceedings by FERC.

Research

AP&L, GSU, LP&L, MP&L, and NOPSI are members of the Electric Power Research Institute (EPRI). EPRI conducts a broad range of research in major technical fields related to the electric utility industry. Entergy participates in various EPRI projects, based on Entergy's needs and available resources. During 1992, 1993 and 1994, the System contributed approximately $16 million, $17 million and $18 million, respectively, for the various research programs in which Entergy was involved.

Item 2. Properties

Refer to Item 1, "Business - Property," for information regarding the properties of the registrants.

Item 3. Legal Proceedings

Refer to Item 1, "Business - Rate Matters and Regulation," for details of the registrants' material rate proceedings and other regulatory proceedings and litigation that are pending or that terminated in the fourth quarter of 1994.

Item 4. Submission of Matters to a Vote of Security Holders

During the fourth quarter of 1994, no matters that would be described in response to this item were submitted to a vote of the security holders of Entergy Corporation, AP&L, GSU, LP&L, MP&L, NOPSI, or System Energy.

Item 5. Market for Registrants' Common Equity and Related Stockholder Matters

Entergy Corporation. The shares of Entergy Corporation's common stock are listed on the New York, Chicago, and Pacific Stock Exchanges.

The high and low prices for each quarterly period in 1994 and 1993, were as follows:

	1994		1993	
	High	Low	High	Low
	(In Dollars)			
First	37 3/8	31 1/8	36 1/2	32 1/2
Second	32 1/8	24 5/8	38 1/4	33 1/4
Third	26 1/4	22 5/8	39 7/8	36 1/4
Fourth	24 3/4	21 1/4	39 1/4	35 1/8

Eight consecutive quarterly cash dividends on common stock were paid to stockholders of Entergy Corporation in 1994 and 1993. Dividends of 45 cents per share were paid in each of the four quarters of 1994. In 1993, dividends of 40 cents per share were paid in each of the first three quarters and dividends of 45 cents per share were paid in the last quarter.

As of February 28, 1995, there were 103,100 stockholders of record of Entergy Corporation.

For information with respect to Entergy Corporation's future ability to pay dividends, refer to Note 7 of Entergy Corporation and Subsidiaries' Notes to Consolidated Financial Statements, "Dividend Restrictions." In addition to the restrictions described in Note 7, the Holding Company Act provides that, without approval of the SEC, the unrestricted, undistributed retained earnings of any Entergy Corporation subsidiary are not available for distribution to Entergy Corporation's common stockholders until such earnings are made available to Entergy Corporation through the declaration of dividends by such subsidiaries.

AP&L, GSU, LP&L, MP&L, NOPSI, and System Energy. There is no market for the common stock of System Energy and the System operating companies, all of which is owned by Entergy Corporation. Prior to December 31, 1993, GSU's common stock was publicly held. Effective with the Merger, all shares of GSU common stock were acquired by Entergy Corporation. No cash dividends on common stock were paid by GSU to its stockholders in 1993. Cash dividends on common stock paid by AP&L, GSU, LP&L, MP&L, NOPSI, and System Energy to Entergy Corporation during 1994 and 1993, were as follows:

	1994	1993
	(In Millions)	
AP&L	$80.0	$156.3
GSU	289.1	-
LP&L	167.1	167.6
MP&L	45.6	85.8
NOPSI	33.3	43.9
System Energy	148.3	233.1

For information with respect to restrictions that limit the ability of System Energy and the System operating companies to pay dividends, and for information with respect to dividends paid to Entergy Corporation by its

subsidiaries subsequent to December 31, 1994, refer respectively, to Note 6 of System Energy's and Note 7 of AP&L's, GSU's, LP&L's, MP&L's, and NOPSI's Notes to Financial Statements, "Dividend Restrictions."

Item 6. Selected Financial Data

Entergy Corporation. Refer to information under the heading "Entergy Corporation and Subsidiaries Selected Financial Data - Five-Year Comparison."

AP&L. Refer to information under the heading "Arkansas Power & Light Company Selected Financial Data - Five-Year Comparison."

GSU. Refer to information under the heading "Gulf States Utilities Company Selected Financial Data - Five-Year Comparison."

LP&L. Refer to information under the heading "Louisiana Power & Light Company Selected Financial Data - Five-Year Comparison."

MP&L. Refer to information under the heading "Mississippi Power & Light Company Selected Financial Data - Five-Year Comparison."

NOPSI. Refer to information under the heading "New Orleans Public Service Inc. Selected Financial Data - Five-Year Comparison."

System Energy. Refer to information under the heading "System Energy Resources, Inc. Selected Financial Data - Five-Year Comparison."

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

Entergy Corporation. Refer to information under the heading "ENTERGY CORPORATION AND SUBSIDIARIES MANAGEMENT'S FINANCIAL DISCUSSION AND ANALYSIS."

AP&L. Refer to information under the heading "ARKANSAS POWER & LIGHT COMPANY MANAGEMENT'S FINANCIAL DISCUSSION AND ANALYSIS."

GSU. Refer to information under the heading "GULF STATES UTILITIES COMPANY MANAGEMENT'S FINANCIAL DISCUSSION AND ANALYSIS."

LP&L. Refer to information under the heading "LOUISIANA POWER & LIGHT COMPANY MANAGEMENT'S FINANCIAL DISCUSSION AND ANALYSIS."

MP&L. Refer to information under the heading "MISSISSIPPI POWER & LIGHT COMPANY MANAGEMENT'S FINANCIAL DISCUSSION AND ANALYSIS."

NOPSI. Refer to information under the heading "NEW ORLEANS PUBLIC SERVICE INC. MANAGEMENT'S FINANCIAL DISCUSSION AND ANALYSIS."

System Energy. Refer to information under the heading "SYSTEM ENERGY RESOURCES, INC. MANAGEMENT'S FINANCIAL DISCUSSION AND ANALYSIS."

Item 8. Financial Statements and Supplementary Data.

INDEX TO FINANCIAL STATEMENTS

Entergy Corporation and Subsidiaries:

Definitions	61
Report of Management	64
Audit Committee Chairman's Letter	65
Report of Independent Accountants	66
Independent Auditors' Report	67
Consolidated Balance Sheets, December 31, 1994 and 1993	68
Statements of Consolidated Cash Flows For the Years Ended December 31, 1994, 1993 and 1992	70
Management's Financial Discussion and Analysis	72
Statements of Consolidated Income For the Years Ended December 31, 1994, 1993 and 1992	75
Statements of Consolidated Retained Earnings and Paid-In Capital for the Years Ended December 31, 1994, 1993 and 1992	76
Management's Financial Discussion and Analysis (continued)	77
Notes to Consolidated Financial Statements	86
Selected Financial Data - Five-Year Comparison	120

AP&L:

Definitions	122
Report of Management	124
Audit Committee Chairman's Letter	125
Report of Independent Accountants	126
Independent Auditors' Report	127
Balance Sheets, December 31, 1994 and 1993	128
Statements of Cash Flows For the Years Ended December 31, 1994, 1993 and 1992	130
Management's Financial Discussion and Analysis	131
Statements of Income For the Years Ended December 31, 1994, 1993 and 1992	132
Statements of Retained Earnings for the Years Ended December 31, 1994, 1993 and 1992	133
Management's Financial Discussion and Analysis (continued)	134
Notes to Financial Statements	139
Selected Financial Data - Five-Year Comparison	156

GSU:

Definitions	158
Report of Management	160
Audit Committee Chairman's Letter	161
Report of Independent Accountants	163
Balance Sheets, December 31, 1994 and 1993	164
Statements of Cash Flows For the Years Ended December 31, 1994, 1993 and 1992	166
Management's Financial Discussion and Analysis	167
Statements of Income (Loss) For the Years Ended December 31, 1994, 1993 and 1992	168
Statements of Retained Earnings and Paid-In Capital for the Years Ended December 31, 1994, 1993 and 1992	169
Management's Financial Discussion and Analysis (continued)	170
Notes to Financial Statements	176
Selected Financial Data - Five-Year Comparison	203

LP&L:

Definitions	206
Report of Management	208
Audit Committee Chairman's Letter	209
Report of Independent Accountants	210
Independent Auditors' Report	211
Balance Sheets, December 31, 1994 and 1993	212
Statements of Cash Flows For the Years Ended December 31, 1994, 1993 and 1992	214
Management's Financial Discussion and Analysis	215
Statements of Income For the Years Ended December 31, 1994, 1993 and 1992	216
Statements of Retained Earnings for the Years Ended December 31, 1994, 1993 and 1992	217
Management's Financial Discussion and Analysis (continued)	218
Notes to Financial Statements	222
Selected Financial Data - Five-Year Comparison	239

MP&L:
Definitions 242
Report of Management 244
Audit Committee Chairman's Letter 245
Report of Independent Accountants 246
Independent Auditors' Report 247
Balance Sheets, December 31, 1994 and 1993 248
Statements of Cash Flows For the Years Ended December 31, 1994, 1993 and 1992 250
Management's Financial Discussion and Analysis 251
Statements of Income For the Years Ended December 31, 1994, 1993 and 1992 252
Statements of Retained Earnings for the Years Ended December 31, 1994, 1993 and 1992 253
Management's Financial Discussion and Analysis (continued) 254
Notes to Financial Statements 259
Selected Financial Data - Five-Year Comparison 274
NOPSI:
Definitions 276
Report of Management 278
Audit Committee Chairman's Letter 279
Report of Independent Accountants 280
Independent Auditors' Report 281
Balance Sheets, December 31, 1994 and 1993 282
Statements of Cash Flows For the Years Ended December 31, 1994, 1993 and 1992 284
Management's Financial Discussion and Analysis 285
Statements of Income For the Years Ended December 31, 1994, 1993 and 1992 286
Statements of Retained Earnings for the Years Ended December 31, 1994, 1993 and 1992 287
Management's Financial Discussion and Analysis (continued) 288
Notes to Financial Statements 293
Selected Financial Data - Five-Year Comparison 308
System Energy:
Definitions 310
Report of Management 312
Audit Committee Chairman's Letter 313
Report of Independent Accountants 314
Independent Auditors' Report 315
Balance Sheets, December 31, 1994 and 1993 316
Statements of Cash Flows For the Years Ended December 31, 1994, 1993 and 1992 318
Management's Financial Discussion and Analysis 319
Statements of Income For the Years Ended December 31, 1994, 1993 and 1992 320
Statements of Retained Earnings for the Years Ended December 31, 1994, 1993 and 1992 321
Management's Financial Discussion and Analysis (continued) 322
Notes to Financial Statements 325
Selected Financial Data - Five-Year Comparison 340

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ENTERGY

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ENTERGY CORPORATION AND SUBSIDIARIES

DEFINITIONS

Certain abbreviations or acronyms used in the Financial Statements, Notes to Financial Statements, and Management's Financial Discussion and Analysis are defined below:

Abbreviation or Acronym	Term
AFUDC	Allowance for Funds Used During Construction
ANO	Arkansas Nuclear One Steam Electric Generating Station
ANO 2	Unit No. 2 of ANO
AP&L	Arkansas Power & Light Company
APSC	Arkansas Public Service Commission
Cajun	Cajun Electric Power Cooperative, Inc.
Council	Council of the City of New Orleans, Louisiana
Entergy or System	Entergy Corporation and its various direct and indirect subsidiaries
Entergy Enterprises	Entergy Enterprises, Inc.
Entergy Operations	Entergy Operations, Inc., a subsidiary of Entergy Corporation that has operating responsibility for Grand Gulf 1, Waterford 3, ANO, and River Bend
Entergy Services	Entergy Services, Inc.
Entergy Power	Entergy Power, Inc., a subsidiary of Entergy Corporation that markets capacity and energy for resale from certain generating facilities to other parties, principally non-affiliates
EPAct	The Energy Policy Act of 1992
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
G&R Bonds	General and Refunding Mortgage Bonds issued and issuable by MP&L and NOPSI
Grand Gulf 1	Unit No. 1 of the Grand Gulf Steam Electric Generating Station (nuclear)
Grand Gulf 2	Unit No. 2 of the Grand Gulf Steam Electric Generating Station (nuclear)
GSU	Gulf States Utilities Company (including wholly owned subsidiaries - Varibus Corporation, GSG&T, Inc., Prudential Oil and Gas, Inc., and Southern Gulf Railway Company)

Abbreviation or Acronym	Term
KWH	Kilowatt-Hour(s)
LP&L	Louisiana Power & Light Company
LPSC	Louisiana Public Service Commission
Merger	The combination transaction, consummated on December 31, 1993, by which GSU became a subsidiary of Entergy Corporation and Entergy Corporation became a Delaware corporation
Money Pool	Entergy Money Pool, which allows certain System companies to borrow from, or lend to, certain other System companies
MP&L	Mississippi Power & Light Company
MPSC	Mississippi Public Service Commission
1991 NOPSI Settlement	Agreement, retroactive to October 4, 1991, among NOPSI, the Council, the Alliance for Affordable Energy, Inc., and others that settled certain Grand Gulf 1 prudence issues and pending litigation related to the resolution (including the Determinations and Order referred to therein) adopted by the Council on February 4, 1988, disallowing NOPSI's recovery of $135 million of previously deferred Grand Gulf 1-related costs
NOPSI	New Orleans Public Service Inc.
PUCT	Public Utility Commission of Texas
Rate Cap	The level of GSU's retail electric base rates in effect at December 31, 1993, for the Louisiana retail jurisdiction, and the level in effect prior to the Texas Cities Rate Settlement for the Texas retail jurisdiction, that may not be exceeded for the five years following December 31, 1993
River Bend	River Bend Steam Electric Generating Station (nuclear), owned 70% by GSU
RUS	Rural Utility Services (formerly the Rural Electrification Administration or "REA")
SEC	Securities and Exchange Commission
SFAS	Statement of Financial Accounting Standards promulgated by the FASB
SFAS 106	SFAS 106, "Employers' Accounting for Postretirement Benefits Other Than Pensions"
SFAS 109	SFAS 109, "Accounting for Income Taxes"

Abbreviation or Acronym	Term
System Agreement	Agreement, effective January 1, 1983, as subsequently modified by the FERC, among the System operating companies relating to the sharing of generating capacity and other power resources
System Energy	System Energy Resources, Inc.
System Fuels	System Fuels, Inc.
System operating companies	AP&L, GSU, LP&L, MP&L, and NOPSI, collectively
System or Entergy	Entergy Corporation and its various direct and indirect subsidiaries
Waterford 3	Unit No. 3 of the Waterford Steam Electric Generating Station (nuclear)

ENTERGY CORPORATION AND SUBSIDIARIES

REPORT OF MANAGEMENT

The management of Entergy Corporation has prepared and is responsible for the financial statements and related financial information included herein. The financial statements are based on generally accepted accounting principles. Financial information included elsewhere in this report is consistent with the financial statements.

To meet its responsibilities with respect to financial information, management maintains and enforces a system of internal accounting controls that is designed to provide reasonable assurance, on a cost-effective basis, as to the integrity, objectivity, and reliability of the financial records, and as to the protection of assets. This system includes communication through written policies and procedures, an employee Code of Conduct, and an organizational structure that provides for appropriate division of responsibility and the training of personnel. This system is also tested by a comprehensive internal audit program.

The independent public accountants provide an objective assessment of the degree to which management meets its responsibility for fairness of financial reporting. They regularly evaluate the system of internal accounting controls and perform such tests and other procedures as they deem necessary to reach and express an opinion on the fairness of the financial statements.

Management believes that these policies and procedures provide reasonable assurance that its operations are carried out with a high standard of business conduct.

EDWIN LUPBERGER
Chairman and Chief Executive Officer

GERALD D. MCINVALE
Senior Vice President and
Chief Financial Officer

ENTERGY CORPORATION AND SUBSIDIARIES

AUDIT COMMITTEE CHAIRMAN'S LETTER

The Entergy Corporation Board of Directors' Audit Committee is comprised of four directors, who are not officers of Entergy Corporation: H. Duke Shackelford (Chairman), Lucie J. Fjeldstad, Dr. Norman C. Francis, and James R. Nichols. The committee held four meetings during 1994.

The Audit Committee oversees Entergy Corporation's financial reporting process on behalf of Entergy Corporation's Board of Directors. In fulfilling its responsibility, the committee recommended to the board, subject to stockholder approval, the selection of Entergy Corporation's independent public accountants (Coopers & Lybrand L.L.P.).

The Audit Committee discussed with Entergy's internal auditors and the independent public accountants the overall scope and specific plans for their respective audits, as well as Entergy Corporation's consolidated financial statements and the adequacy of Entergy Corporation's internal controls. The committee met, together and separately, with Entergy's internal auditors and independent public accountants, without management present, to discuss the results of their audits, their evaluation of Entergy Corporation's internal controls, and the overall quality of Entergy Corporation's financial reporting. The meetings also were designed to facilitate and encourage any private communication between the committee and the internal auditors or independent public accountants.

H. DUKE SHACKELFORD
Chairman, Audit Committee

REPORT OF INDEPENDENT ACCOUNTANTS

To the Board of Directors and Shareholders of
Entergy Corporation

We have audited the accompanying consolidated balance sheet of Entergy Corporation and Subsidiaries as of December 31, 1994, and the related statements of consolidated income, retained earnings and paid-in capital and cash flows for the year then ended. These financial statements are the responsibility of the Corporation's management. Our responsibility is to express an opinion on these financial statements based on our audit. The consolidated financial statements of Entergy Corporation and Subsidiaries as of December 31, 1993 and for the years ended December 31, 1993 and 1992, were audited by other auditors, whose report, dated February 11, 1994, included explanatory paragraphs that (i) described changes in 1993 in methods of accounting for revenues, income taxes and postretirement benefits other than pensions (Notes 1, 3 and 10, respectively); (ii) uncertainties regarding costs capitalized by Gulf States Utilities Company for its River Bend Unit 1 Nuclear Generating Plant (River Bend) and other rate-related contingencies which may result in a refund of revenues previously collected (Note 2); and, (iii) an uncertainty regarding civil actions against Gulf States Utilities Company (Note 8).

We conducted our audit in accordance with generally accepted auditing standards. Those standards require that we plan and perform the audit to obtain reasonable assurance 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 audit provides a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Entergy Corporation and Subsidiaries as of December 31, 1994, and the results of their operations and their cash flows for the year then ended in conformity with generally accepted accounting principles.

As discussed in Note 2 to the consolidated financial statements, the net amount of capitalized costs for River Bend exceed those costs currently being recovered through rates. At December 31, 1994, approximately $685 million is not currently being recovered through rates. If current regulatory and court orders are not modified, a write-off of all or a portion of such costs may be required. Additionally, as discussed in Note 2 to the consolidated financial statements, other rate-related contingencies exist which may result in refunds of revenues previously collected. The extent of such write-off of capitalized River Bend costs or refunds of revenues previously collected, if any, will not be determined until appropriate rate proceedings and court appeals have been concluded. Accordingly, the accompanying consolidated financial statements do not include any adjustments or provision for write-off or refund that might result from the outcome of these uncertainties.

As discussed in Note 8 to the consolidated financial statements, civil actions have been initiated against Gulf States Utilities Company to, among other things, recover the co-owner's investment in River Bend and to annul the River Bend Joint Ownership Participation and Operating Agreement. The ultimate outcome of these proceedings cannot presently be determined.

COOPERS & LYBRAND L.L.P.
New Orleans, Louisiana
February 21, 1995, except for the last paragraph
of "Filings with the PUCT and Texas Cities" in
Note 2, as to which the date is March 20, 1995

INDEPENDENT AUDITORS' REPORT

To the Shareholders and the Board of Directors of
Entergy Corporation

We have audited the accompanying consolidated balance sheet of Entergy Corporation and subsidiaries as of December 31, 1993, and the related statements of consolidated income, retained earnings and paid-in capital, and cash flows for each of the two years in the period ended December 31, 1993. These financial statements are the responsibility of the Corporation's management. Our responsibility is to express an opinion on these financial statements based on our audits. We did not audit the financial statements of Gulf States Utilities Company (a consolidated subsidiary acquired on December 31, 1993), which statements reflect total assets constituting 31% of consolidated total assets at December 31, 1993. Those statements were audited by other auditors whose report (which included explanatory paragraphs regarding the uncertainties discussed in the fourth and fifth paragraphs below) has been furnished to us, and our opinion, insofar as it relates to the amounts included for Gulf States Utilities Company, is based solely on the report of such other auditors.

We conducted our audits in accordance with generally accepted auditing standards. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits and the report of the other auditors provide a reasonable basis for our opinion.

In our opinion, based on our audits and the report of the other auditors, such consolidated financial statements present fairly, in all material respects, the financial position of Entergy Corporation and subsidiaries at December 31, 1993, and the results of their operations and their cash flows for each of the two years in the period ended December 31, 1993 in conformity with generally accepted accounting principles.

The Corporation acquired a 70% interest in River Bend Unit 1 Nuclear Generating Plant (River Bend) through its acquisition of Gulf States Utilities Company on December 31, 1993. As discussed in Note 2 to the consolidated financial statements, the net amount of capitalized costs for River Bend exceed those costs currently being recovered through rates. At December 31, 1993, approximately $747 million is not currently being recovered through rates. If current regulatory and court orders are not modified, a write-off of all or a portion of such costs may be required. Additionally, as discussed in Note 2 to the consolidated financial statements, other rate-related contingencies exist which may result in a refund of revenues previously collected. The extent of such write-off of capitalized River Bend costs or refund of revenues previously collected, if any, will not be determined until appropriate rate proceedings and court appeals have been concluded. Accordingly, the accompanying 1993 consolidated financial statements do not include any adjustments that might result from the outcome of these uncertainties.

As discussed in Note 8 to the consolidated financial statements, civil actions have been initiated against Gulf States Utilities Company to, among other things, recover the co-owner's investment in River Bend and to annul the related joint ownership participation and operating agreement. The ultimate outcome of these proceedings, including their impact on Gulf States Utilities Company, cannot presently be determined. Accordingly, the accompanying 1993 consolidated financial statements do not include any adjustments that might result from the outcome of this uncertainty.

As discussed in Note 1 to the consolidated financial statements, certain of the Corporation's subsidiaries changed their method of accounting for revenues in 1993 and, as discussed in Notes 3 and 10 to the consolidated financial statements, in 1993 the Corporation changed its methods of accounting for income taxes and postretirement benefits other than pensions, respectively.

DELOITTE & TOUCHE LLP
New Orleans, Louisiana
February 11, 1994

ENTERGY CORPORATION AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
ASSETS

	December 31,	
	1994	1993
	(In Thousands)	
Utility Plant:		
Electric	$21,184,013	$20,848,844
Plant acquisition adjustment - GSU	487,955	380,117
Electric plant under leases	668,846	663,024
Property under capital leases - electric	161,950	175,276
Natural gas	164,013	156,452
Steam products	77,307	75,689
Construction work in progress	476,816	533,112
Nuclear fuel under capital leases	265,520	329,433
Nuclear fuel	70,147	17,760
Total	23,556,567	23,179,707
Less - accumulated depreciation and amortization	7,639,549	7,157,981
Utility plant - net	15,917,018	16,021,726
Other Property and Investments:		
Decommissioning trust funds	207,395	172,960
Other	240,745	183,597
Total	448,140	356,557
Current Assets:		
Cash and cash equivalents:		
Cash	87,700	27,345
Temporary cash investments - at cost, which approximates market	526,207	536,404
Total cash and cash equivalents	613,907	563,749
Special deposits	8,074	36,612
Notes receivable	19,190	17,710
Accounts receivable:		
Customer (less allowance for doubtful accounts of $6.7 million in 1994 and $8.8 million in 1993)	325,410	315,796
Other	66,651	81,931
Accrued unbilled revenues	240,610	257,321
Fuel inventory	93,211	110,204
Materials and supplies - at average cost	365,956	360,353
Rate deferrals	380,612	333,311
Prepayments and other	98,811	98,144
Total	2,212,432	2,175,131
Deferred Debits and Other Assets:		
Regulatory Assets:		
Rate deferrals	1,451,926	1,876,051
SFAS 109 regulatory asset - net	1,417,646	1,385,824
Unamortized loss on reacquired debt	232,420	210,698
Other regulatory assets	316,878	283,846
Long-term receivables	277,830	228,030
Other	339,201	338,834
Total	4,035,901	4,323,283
TOTAL	$22,613,491	$22,876,697

See Notes to Consolidated Financial Statements.

ENTERGY CORPORATION AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
CAPITALIZATION AND LIABILITIES

	December 31,	
	1994	1993
	(In Thousands)	
Capitalization:		
Common stock, $0.01 par value, authorized 500,000,000 shares; issued 230,017,485 shares in 1994 and 231,219,737 shares in 1993	$2,300	$2,312
Paid-in capital	4,202,134	4,223,682
Retained earnings	2,223,739	2,310,082
Less - treasury stock (2,608,908 shares in 1994)	77,378	-
Total common shareholders' equity	6,350,795	6,536,076
Subsidiaries' preference stock	150,000	150,000
Subsidiaries' preferred stock:		
Without sinking fund	550,955	550,955
With sinking fund	299,946	349,053
Long-term debt	7,093,473	7,355,962
Total	14,445,169	14,942,046
Other Noncurrent Liabilities:		
Obligations under capital leases	273,947	322,867
Other	310,977	296,572
Total	584,924	619,439
Current Liabilities:		
Currently maturing long-term debt	349,085	322,010
Notes payable	171,867	43,667
Accounts payable	471,120	413,727
Customer deposits	134,478	127,524
Taxes accrued	92,578	118,267
Accumulated deferred income taxes	40,313	73,933
Interest accrued	195,639	210,894
Dividends declared	13,599	13,404
Deferred revenue - gas supplier judgment proceeds	-	14,632
Deferred fuel cost	27,066	4,528
Obligations under capital leases	151,904	194,015
Reserve for rate refund	56,972	-
Other	327,330	233,313
Total	2,031,951	1,769,914
Deferred Credits:		
Accumulated deferred income taxes	3,915,138	3,829,041
Accumulated deferred investment tax credits	649,898	793,375
Other	986,411	922,882
Total	5,551,447	5,545,298
Commitments and Contingencies (Notes 2, 8, and 9)		
TOTAL	$22,613,491	$22,876,697

See Notes to Consolidated Financial Statements

ENTERGY CORPORATION AND SUBSIDIARIES
STATEMENTS OF CONSOLIDATED CASH FLOWS

	For the Years Ended December 31,		
	1994	1993	1992
		(In Thousands)	
Operating Activities:			
Net income	$341,841	$551,930	$437,637
Noncash items included in net income:			
Cumulative effect of a change in accounting principle	-	(93,841)	-
Change in rate deferrals/excess capacity-net	394,344	200,532	109,153
Depreciation and decommissioning	656,896	443,550	424,958
Deferred income taxes and investment tax credits	(123,503)	17,669	118,562
Allowance for equity funds used during construction	(11,903)	(8,049)	(7,355)
Amortization of deferred revenues	(14,632)	(42,470)	(38,646)
Gain on sale of property - net	-	-	(19,612)
Changes in working capital:			
Receivables	22,377	(40,682)	(19,150)
Fuel inventory	16,993	(1,161)	20,008
Accounts payable	57,393	(9,167)	(54,559)
Taxes accrued	(25,689)	(32,761)	28,561
Interest accrued	(15,255)	(758)	(10,845)
Reserve for rate refund	56,972	-	
Other working capital accounts	144,297	51,100	(12,428)
Refunds to customers - gas contract settlement	-	(56,027)	(56,066)
Decommissioning trust contributions	(24,755)	(20,402)	(20,896)
Provision for estimated losses and reserves	22,522	20,832	(24,911)
Other	39,869	94,092	(43,185)
Net cash flow provided by operating activities	1,537,767	1,074,387	831,226
Investing Activities:			
Merger with GSU - cash paid	-	(250,000)	-
Merger with GSU - cash acquired	-	261,349	-
Construction / capital expenditures	(676,180)	(512,235)	(438,845)
Allowance for equity funds used during construction	11,903	8,049	7,355
Nuclear fuel purchases	(179,932)	(118,216)	(60,359)
Proceeds from sale/leaseback of nuclear fuel	128,675	121,526	62,332
Investment in nonregulated/nonutility properties	(49,859)	(76,870)	(35,189)
Proceeds received from sale of property	26,000	-	67,985
Decrease in other temporary investments	-	17,012	114,651
Net cash flow used in investing activities	(739,393)	(549,385)	(282,070)
Financing Activities:			
Proceeds from the issuance of:			
First mortgage bonds	59,410	605,000	637,114
General and refunding mortgage bonds	24,534	350,000	65,000
Preferred stock	-	-	120,999
Other long-term debt	164,699	106,070	48,067
Premium and expense on refinancing sale/leaseback bonds	(48,497)	-	-
Retirement of:			
First mortgage bonds	(303,800)	(911,692)	(1,009,320)
General and refunding mortgage bonds	(45,000)	(99,400)	-
Other long-term debt	(148,962)	(69,982)	(17,412)
Repurchase of common stock	(119,486)	(20,558)	(105,673)
Redemption of preferred stock	(49,091)	(56,000)	(109,369)
Common stock dividends paid	(410,223)	(287,483)	(256,117)
Changes in short-term borrowings	128,200	43,000	-
Net cash flow used in financing activities	(748,216)	(341,045)	(626,711)
Net increase (decrease) in cash and cash equivalents	50,158	183,957	(77,555)
Cash and cash equivalents at beginning of period	563,749	379,792	457,347
Cash and cash equivalents at end of period	$613,907	$563,749	$379,792

ENTERGY CORPORATION AND SUBSIDIARIES
STATEMENTS OF CONSOLIDATED CASH FLOWS

	For the Years Ended December 31,		
	1994	1993	1992
		(In Thousands)	
SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION:			
Cash paid during the period for:			
Interest - net of amount capitalized	$660,150	$485,876	$570,199
Income taxes	$218,667	$159,659	$125,079
Noncash investing and financing activities:			
Capital lease obligations incurred	$88,574	$126,812	$75,040
Deficiency of fair value of decommissioning trust assets over amount invested	($2,198)	-	-
Merger with GSU - common stock issued	-	$2,031,101	-

See Notes to Consolidated Financial Statements.

ENTERGY CORPORATION AND SUBSIDIARIES
MANAGEMENT'S FINANCIAL DISCUSSION AND ANALYSIS
LIQUIDITY AND CAPITAL RESOURCES

Liquidity is important to Entergy due to the capital intensive nature of its business, which requires large investments in long-lived assets. While large capital expenditures for the construction of new generating capacity are not currently planned, the System does require significant capital resources for the periodic maturity of certain series of debt and preferred stock and ongoing construction expenditures. Net cash flow from operations totaled $1,538 million, $1,074 million, and $831 million in 1994, 1993, and 1992, respectively. In recent years, this cash flow, supplemented by cash on hand, has been sufficient to meet substantially all investing and financing requirements, including capital expenditures, dividends, and debt/preferred stock maturities. Entergy's ability to fund these capital requirements with cash from operations results, in part, from continued efforts to streamline operations and reduce costs as well as collections under Grand Gulf 1 and River Bend rate phase-in plans, which exceed the current cash requirements for Grand Gulf 1-related costs. (In the income statement, these revenue collections are offset by the amortization of previously deferred costs; therefore, there is no effect on net income.) These phase-in plans will continue to contribute to Entergy's cash position for the next several years. Further, Entergy Corporation's subsidiaries have the ability to meet future capital requirements through future debt or preferred stock issuances, as discussed below. See Note 8 for additional information on the System's capital and refinancing requirements in 1995 - 1997. Also, to the extent current market interest and dividend rates allow, the System operating companies and System Energy may continue to refinance high-cost debt and preferred stock prior to maturity.

Productive investment by Entergy Corporation of excess funds is necessary to enhance the long-term value of its common stock. In 1994, Entergy Corporation invested in the Hub River Company which is constructing a generating station near Karachi, Pakistan. In 1993, Entergy Corporation invested in an electric distribution company and a high-voltage transmission system in Argentina. In 1992, Entergy Corporation invested in a generating facility in Argentina, an independent power plant in Virginia, a lighting efficiency services company, and a company that develops energy management and other technology applications. Entergy Corporation may invest up to $150 million per year for the next several years in nonregulated business opportunities. See "Significant Factors and Known Trends - Nonregulated Investments" for additional information.

Certain agreements and restrictions limit the amount of mortgage bonds and preferred stock that can be issued by the System operating companies and System Energy. Based on the most restrictive applicable tests as of December 31, 1994, and an assumed annual interest or dividend rate of 9.25%, the System operating companies could have issued bonds or preferred stock in the following amounts, respectively: AP&L - $253 million and $468 million; GSU - $0 million and $0 million; LP&L - $107 million and $784 million; MP&L - $246 million and $95 million; and NOPSI - $89 million and $17 million. System Energy could also have issued $241 million of bonds, but its charter does not presently provide for the issuance of preferred stock. In addition, the System operating companies and System Energy have the conditional ability to issue bonds against the retirement of bonds, in some cases without meeting an earnings coverage test. Although GSU was precluded from issuing first mortgage bonds under its earnings coverage test as of December 31, 1994, GSU has the ability to issue $578 million of first mortgage bonds against the retirement of first mortgage bonds without meeting such test. AP&L may also issue preferred stock to refund outstanding preferred stock without meeting an earnings coverage test. GSU has no limitations on the issuance of preference stock. See Note 4 for information on the System's short-term borrowings.

Entergy Corporation's current primary capital requirements are to periodically invest in, or make loans to, its subsidiaries. Entergy Corporation expects to meet these requirements in 1995 - 1997 with internally generated funds and cash on hand. Further, Entergy Corporation paid $410.2 million of dividends on its common stock in 1994. Declarations of dividends on common stock are made at the discretion of Entergy Corporation's Board of Directors (Board). It is anticipated that management will not recommend future dividend increases to the Board unless such increases are justified by sustained earnings growth of Entergy Corporation and its subsidiaries. Entergy Corporation receives funds through dividend payments from its subsidiaries. During 1994, these common stock dividend payments totaled $763.4 million. Certain restrictions may limit the amount of these distributions. See Note 7 for additional information.

See Notes 2 and 8 for information regarding litigation with Cajun and River Bend rate appeals. Substantial write-offs or charges resulting from adverse rulings in these matters could result in substantial additional net losses being reported by Entergy and GSU in 1995 and subsequent periods, with resulting substantial adverse adjustments to common shareholder's equity. Also, adverse resolution of these matters could adversely affect GSU's ability to continue to pay dividends and obtain financing, which could in turn affect GSU's liquidity.

Entergy Corporation has a program to repurchase shares of its outstanding common stock. The timing and amount of such repurchases depend upon market conditions and Board authorization. Entergy Corporation has requested, but not yet received, SEC authorization for a $300 million bank line of credit, the proceeds of which are expected to be used for common stock repurchases, investments in nonregulated and nonutility businesses, and other optional activities. Certain parties have intervened in this proceeding, and the application is pending. See Notes 4 and 5 for additional information.

Increasing competition in the utility industry brings an increased need to stabilize costs and reduce retail rates. See "Significant Factors and Known Trends - Competition" for additional information on rate issues affecting the System.

On March 20, 1995, the PUCT ordered GSU to implement a $72.9 million annual base rate reduction for the period March 31, 1994, through September 1, 1994, decreasing to an annual base rate reduction of $52.9 million after September 1, 1994. In accordance with the Merger agreement, the rate reduction is applied retroactively to March 31, 1994. As a result, GSU recorded a $57 million reserve for rate refund in 1994. See Note 2 for additional information.

In March 1994, the MPSC issued a final order adopting a formulary incentive rate plan. The order also adopted previously agreed-upon stipulations of a required return on equity of 11% and certain accounting adjustments that resulted in a 4.3% ($28.1 million) reduction in MP&L's June 30, 1993, test-year base revenues effective March 25, 1994. The plan allows for periodic small adjustments in rates based on an annual comparison of earned to benchmark rates of return and upon certain other performance factors. See Note 2 for additional information.

As discussed in Note 2, NOPSI agreed to reduce electric and gas rates and issue credits and refunds to customers pursuant to the 1994 NOPSI Settlement. Under the terms of the settlement, NOPSI implemented rate reductions totaling $44.9 million effective January 1, 1995. NOPSI will implement an additional $4.4 million rate reduction on October 31, 1995. In addition, the 1994 NOPSI Settlement requires NOPSI to credit its customers $25 million over a 21-month period, beginning January 1, 1995, in order to resolve disputes with the Council regarding the interpretation of the 1991 NOPSI Settlement. The 1994 NOPSI Settlement also required NOPSI to refund $9.3 million of overcollections associated with Grand Gulf 1 operating costs and $10.5 million of refunds associated with the settlement by System Energy of a FERC tax audit. See Note 2 for additional information on the 1994 NOPSI Settlement.

As discussed in Note 2, in November 1994, FERC approved an agreement settling a long-standing dispute involving income tax allocation procedures of System Energy. In connection with this settlement, System Energy refunded approximately $61.7 million to AP&L, LP&L, MP&L, and NOPSI, which in turn have made or will make refunds or credits to their customers (except for those portions attributable to AP&L's and LP&L's retained share of Grand Gulf 1 costs). Additionally, System Energy will refund a total of approximately $62 million, plus interest, to AP&L, LP&L, MP&L, and NOPSI over the period through June 2004. AP&L, LP&L, MP&L, and NOPSI also wrote off certain related unamortized balances of deferred investment tax credits. See Note 2 for further information on the FERC Settlement.

Entergy Corporation has agreed to supply to System Energy sufficient capital to (1) maintain System Energy's equity capital at an amount equal to a minimum of 35% of its total capitalization (excluding short-term debt), and (2) permit the continuation of commercial operation of Grand Gulf 1 and to pay in full all indebtedness for borrowed money of System Energy when due under any circumstances. In addition, under supplements to the Capital Funds Agreement assigning System Energy's rights as security for specific debt of System Energy, Entergy Corporation has agreed to make cash capital contributions to enable System Energy to make payments on such debt when due. See Note 8 for additional information.

ENTERGY CORPORATION AND SUBSIDIARIES
STATEMENTS OF CONSOLIDATED INCOME

	For the Years Ended December 31,		
	1994	1993	1992
	(In Thousands, Except Share Data)		
Operating Revenues:			
Electric	$5,797,769	$4,394,346	$4,043,555
Natural gas	118,962	90,991	72,944
Steam products	46,559	-	-
Total	5,963,290	4,485,337	4,116,499
Operating Expenses:			
Operation and maintenance:			
Fuel, fuel-related expenses, and gas purchased for resale	1,446,397	912,233	802,682
Purchased power	350,903	278,070	228,679
Nuclear refueling outage expenses	63,979	76,383	87,885
Other operation and maintenance	1,568,810	1,043,838	1,020,894
Depreciation and decommissioning	656,826	443,550	424,958
Taxes other than income taxes	284,234	199,151	197,895
Income taxes	131,965	251,163	210,081
Rate deferrals:			
Rate deferrals	-	(1,651)	(24,176)
Amortization of rate deferrals	391,365	289,259	209,015
Total	4,894,549	3,491,996	3,157,913
Operating Income	1,068,741	993,341	958,586
Other Income (Deductions):			
Allowance for equity funds used during construction	11,903	8,049	7,355
Miscellaneous - net	20,631	50,957	135,475
Income taxes	241	(33,640)	(46,382)
Total	32,775	25,366	96,448
Interest Charges:			
Interest on long-term debt	665,541	503,797	546,805
Other interest - net	22,354	5,740	12,549
Allowance for borrowed funds used during construction	(9,938)	(5,478)	(5,094)
Preferred dividend requirements of subsidiaries and other	81,718	56,559	63,337
Total	759,675	560,618	617,397
Income before Cumulative Effect of a Change in Accounting Principle	341,841	458,089	437,637
Cumulative effect to January 1, 1993, of Accruing Unbilled Revenues (net of income taxes of $57,188)	-	93,841	-
Net Income	$341,841	$551,930	$437,637
Earnings per average common share before cumulative effect of a change in accounting principle	$1.49	$2.62	$2.48
Earnings per average common share	$1.49	$3.16	$2.48
Dividends declared per common share	$1.80	$1.65	$1.45
Average number of common shares outstanding	228,734,843	174,887,556	176,573,778

See Notes to Consolidated Financial Statements.

ENTERGY CORPORATION AND SUBSIDIARIES
STATEMENTS OF CONSOLIDATED RETAINED EARNINGS AND PAID-IN CAPITAL

	For the Years Ended December 31,		
	1994	1993	1992
		(In Thousands)	
Retained Earnings, January 1	$2,310,082	$2,062,188	$1,943,298
Add:			
Net income	341,841	551,930	437,637
Total	2,651,923	2,614,118	2,380,935
Deduct:			
Dividends declared on common stock	411,806	288,342	255,479
Common stock retirements	13,940	13,906	59,187
Capital stock and other expenses	2,438	1,788	4,081
Total	428,184	304,036	318,747
Retained Earnings, December 31	$2,223,739	$2,310,082	$2,062,188
Paid-in Capital, January 1	$4,223,682	$1,327,589	$1,357,883
Add:			
Loss on reacquisition of subsidiaries' preferred stock	(23)	(20)	(1,323)
Issuance of 56,695,724 shares of common stock in the merger with GSU	-	2,027,325	-
Issuance of 174,552,011 shares of common stock at $.01 par value net of the retirement of 174,552,011 shares of common stock at $5.00 par value	-	871,015	-
Total	4,223,659	4,225,909	1,356,560
Deduct:			
Common stock retirements	22,468	4,389	28,127
Capital stock discounts and other expenses	(943)	(2,162)	844
Total	21,525	2,227	28,971
Paid-in Capital, December 31	$4,202,134	$4,223,682	$1,327,589

See Notes to Consolidated Financial Statements.

On December 31, 1993, GSU became a subsidiary of Entergy Corporation. In accordance with the purchase method of accounting, the results of operations for the 12 months ended December 31, 1993, of Entergy Corporation and subsidiaries reported in its Statements of Consolidated Income and Cash Flows do not include GSU's results of operations. However, the following discussion between the years 1994 and 1993 is presented with GSU's 1993 results of operations included for comparative purposes. The discussion between the years 1993 and 1992 reflects reported results which do not include GSU.

In the second half of 1994, Entergy recorded certain charges that significantly affected results of operations as discussed below. These charges included, among other things, the FERC Settlement refund, NOPSI rate reductions and credits, Merger-related costs, and restructuring costs (see Notes 2, 11, and 12).

Net Income

Consolidated net income decreased $253.4 million in 1994 due primarily to the one-time recording in 1993 of the cumulative effect of the change in accounting principle for unbilled revenues for AP&L, GSU, MP&L, and NOPSI and a base rate reduction ordered by the PUCT applied retroactively to March 31, 1994 (see Note 2). In addition, net income was impacted by a decrease in revenues, increased Merger-related costs, certain restructuring costs, and decreased miscellaneous income - net, partially offset by a decrease in interest on long-term debt and preferred dividend requirements.

Consolidated net income increased in 1993 due primarily to the one-time recording of the cumulative effect of the change in accounting principle for unbilled revenues for AP&L, MP&L, and NOPSI. This increase was partially offset by the effects of implementing SFAS 109 and SFAS 106, and the impact in March 1992 of an after-tax gain from the sale of AP&L's Missouri properties.

Significant factors affecting the results of operations and causing variances between the years 1994 and 1993, and 1993 and 1992, are discussed under "Revenues and Sales," "Expenses," and "Other" below.

Revenues and Sales

See "Selected Financial Data - Five-Year Comparison," following the notes, for information on operating revenues by source and KWH sales.

Electric operating revenues decreased in 1994 due primarily to rate reductions/credits at GSU, MP&L, and NOPSI, the effects of the 1994 NOPSI Settlement and the FERC Settlement, and decreased fuel adjustment revenues, partially offset by increased retail energy sales and increased collections of previously deferred Grand Gulf 1-related costs.

Electric operating revenues were higher in 1993 due primarily to increased residential and commercial energy sales resulting from favorable weather conditions, increased industrial sales due to improving market conditions in the petrochemical, lumber, and plywood industries, and increased fuel adjustment revenues and collections of previously deferred Grand Gulf 1-related costs, neither of which affects net income, partially offset by the impact of a System Energy rate reduction settlement.

Expenses

Purchased power decreased in 1994 due primarily to decreased power purchases from nonassociated utilities due to changes in generation requirements for the System operating companies. Purchased power increased in 1993 due to increased power purchases from non-associated utilities, resulting from changes in fuel-related costs and increased energy sales.

Nuclear refueling outage expenses decreased in 1994 due primarily to Grand Gulf 1 outage expenses incurred in 1993. Nuclear refueling outage expenses decreased in 1993 due primarily to a decrease in the number of scheduled and unscheduled refueling outages.

Total income taxes decreased in 1994 due primarily to lower pre-tax book income and the effects of the FERC Settlement. Total income taxes increased in 1993 due primarily to higher pretax income, an increase in the federal income tax rate as a result of the Omnibus Budget Reconciliation Act of 1993, and the implementation of SFAS 109, partially offset by the impact of the March 1992 sale of AP&L's Missouri properties.

The amortization of rate deferrals increased in 1994 and 1993 due primarily to collection of more Grand Gulf 1-related costs from customers.

Interest expense decreased in 1994 due primarily to the refinancing of high-cost debt partially offset by interest recorded on the FERC Settlement. Interest expense decreased in 1993 due primarily to the refinancing of high-cost debt and debt reduction activities.

Preferred dividend requirements decreased in 1994 and 1993 due primarily to stock redemption activities.

Other

Miscellaneous income - net decreased in 1994 due primarily to amortization of plant acquisition adjustment related to the Merger, the adoption of SFAS 116, "Accounting for Contributions Made and Contributions Received" and reduced Grand Gulf 1 carrying charges at AP&L. Miscellaneous income - net decreased in 1993 due primarily to the 1992 pretax gain of approximately $33.7 million from the sale of AP&L's Missouri properties.

Competition

The electric utility industry, including Entergy, is experiencing increased competitive pressures. Entergy is seeking to become a leading competitor in the changing electric energy business. Competition presents Entergy with many challenges. The following have been identified by Entergy as its major competitive challenges.

Retail and Wholesale Rate Issues

Increasing competition in the utility industry brings an increased need to stabilize or reduce retail rates. The retail regulatory philosophy is shifting in some jurisdictions from traditional cost-of-service regulation to incentive-rate regulation. Incentive and performance-based rate plans encourage efficiencies and productivity while permitting utilities and their customers to share in the results. MP&L implemented an incentive-rate plan in 1994 and LP&L filed a performance-based formula rate plan with the LPSC in August 1994. GSU agreed to shared-savings plans as part of the Merger. Recognizing that many industrial customers have energy alternatives, Entergy continues to work with these customers to address their needs. In certain cases, competitive prices are negotiated, using variable-rate designs.

In a settlement with the Council that was approved on December 29, 1994, NOPSI agreed to reduce electric and gas rates and issue credits and refunds to customers. Effective January 1, 1995, NOPSI implemented a $31.8 million permanent reduction in electric base rates and a $3.1 million permanent reduction in gas base rates. These adjustments resolved issues associated with NOPSI's return on equity exceeding 13.76% for the test year ended September 30, 1994. Under the 1991 NOPSI Settlement, NOPSI is recovering from its retail customers its allocable share of certain costs related to Grand Gulf 1. NOPSI's base rates to recover those costs were derived from estimates of those costs made at that time. Any overrecovery of costs is required to be returned to customers. Grand Gulf 1 has experienced lower operating costs than previously estimated, and NOPSI accordingly is reducing its base rates in two steps to more accurately match the current costs related to Grand Gulf 1. On January 1, 1995, NOPSI implemented a $10 million permanent reduction in base electric rates to reflect the reduced costs related to Grand Gulf 1, to be followed by an additional $4.4 million rate reduction on October 31, 1995. These Grand Gulf 1 rate reductions, which are expected to be largely offset by lower operating costs, may reduce NOPSI's after-tax net income by approximately $1.4 million per year beginning November 1, 1995. The next scheduled Grand Gulf 1 phase-in rate increase in the amount of $4.4 million on October 31, 1995, will not be affected by the 1994 NOPSI Settlement.

The 1994 NOPSI Settlement also requires NOPSI to credit its customers $25 million over a 21-month period, beginning January 1, 1995, in order to resolve disputes with the Council regarding the interpretation of the 1991 NOPSI Settlement. NOPSI recorded a $15.4 million net-of-tax reserve associated with the credit in the fourth quarter of 1994. The 1994 NOPSI Settlement further required NOPSI to refund, in December 1994, $13.3 million of credits previously scheduled to be made to customers during the period January 1995 through July 1995. These credits were associated with a July 7, 1994, Council resolution that ordered a $24.95 million rate reduction based on NOPSI's overearnings during the test year ended September 30, 1993. Accordingly, NOPSI recorded an $8 million net-of-tax charge in the fourth quarter of 1994.

MP&L's formulary incentive rate plan allows for periodic small adjustments in rates based on a comparison of earned to benchmark returns and upon certain performance factors. In addition, certain previously agreed-upon stipulations of a required return on equity of 11% and certain accounting adjustments resulted in a 4.3% ($28.1 million) reduction in MP&L's revenues effective March 25, 1994. See Note 2 for further information.

LP&L's five-year rate freeze expired in March 1994. In August 1994, LP&L filed a performance-based formula rate plan with the LPSC. The proposed formula rate plan would continue existing LP&L rates at current levels, while providing financial incentive to reduce costs and maintain high levels of customer satisfaction and system reliability. Hearings were held in March 1995. See Note 2 for additional information.

In connection with the Merger, AP&L and MP&L agreed with their respective retail regulators not to request any general retail rate increases that would take effect before November 1998, with certain exceptions. MP&L also agreed that during this period retail base rates under its formula rate plan would not be increased above the level of rates in effect on November 1, 1993. In connection with the Merger, NOPSI agreed with the Council to reduce its annual electric base rates by $4.8 million effective for bills rendered on or after November 1, 1993. GSU agreed with the LPSC and PUCT to a five-year Rate Cap on retail electric rates, and to pass through to retail customers the fuel savings and a certain percentage of the nonfuel savings created by the Merger. Under the terms of their respective Merger agreements, the LPSC and PUCT have reviewed GSU's base rates during the first post-Merger earnings analysis. The LPSC ordered a $12.7 million annual rate reduction effective January 1, 1995. GSU received an injunction delaying implementation of $8.3 million of the reduction and on January 1, 1995, reduced rates by $4.4 million. The entire $12.7 million is being appealed. On March 20, 1995, the PUCT ordered a $72.9 million annual base rate reduction for the period March 31, 1994, through September 1, 1994, decreasing to an annual base rate reduction of $52.9 million after September 1, 1994. In accordance with the Merger agreement, the rate reduction is applied retroactively to March 31, 1994. The rate reduction is being appealed and no assurance can be given as to the timing or outcome of the appeal. See Note 2 for further information.

Retail wheeling, the transmission by an electric utility of energy produced by another entity over the utility's transmission and distribution system to a retail customer in the electric utility's area of service, is also evolving. Over a dozen states have been or are studying the concept of retail competition. In April 1994, the state of Michigan initiated a five-year experiment that allows limited competition among public utilities. During the same month, the California Public Utilities Commission proposed to deregulate that state's electric power industry, starting on January 1, 1996, to allow the largest industrial customers to select the lowest cost supplier for electricity service. Under the proposal, by the year 2002, smaller companies and residential customers in California would also be able to buy power from any suppliers. The California Public Utilities Commission is currently reviewing its proposal and is expected to make a ruling in the first half of 1995. The retail market for electricity is expected to become more competitive with such moves toward deregulation.

In some areas of the country, municipalities (or comparable entities) whose residents are served at retail by an investor-owned utility pursuant to a franchise are exploring the possibility of establishing new or extending existing distribution systems or seeking new delivery points in order to serve retail customers, especially large industrial customers, that currently receive service from an investor-owned utility. These options depend on the terms of a utility's franchise as well as on state law and regulation. In addition, FERC's authority to order utilities to transmit for a new or expanding municipal system is limited in certain respects. Where successful, however, the establishment of a municipal system or the acquisition by a municipal system of a utility's customers could result in the inability to recover costs that the utility has incurred in serving those customers.

In mid-1994, FERC issued a notice of proposed rulemaking concerning a regulatory framework for dealing with recovery of stranded costs, such as high-cost nuclear generating units, which may be incurred by electric utilities as a result of increased competition. In addition to addressing recovery of stranded costs related to wholesale service, the proposal requested comment as to recovery of retail stranded costs in transmission rates where state regulatory authorities failed to address the issue or were in conflict. Comments and reply comments have been filed, and the matter is pending. The risk of exposure to stranded costs which may result from competition in the industry will depend on the extent and timing of retail competition, the resolution of jurisdictional issues concerning stranded cost recovery, and the extent to which such costs are recovered from departing or remaining customers, among other matters.

Cogeneration projects developed or considered by certain of GSU's industrial customers over the last several years have resulted in GSU developing and securing approval of rates lower than the rates previously approved by the PUCT and LPSC for such industrial customers. Such rates are designed to retain such customers, and to compete for and develop new loads, and do not presently recover GSU's full cost of service. The pricing agreements at non-full cost of service based rates fully recover all related costs but provide only a minimal return. Substantially all of such pricing agreements expire no later than 1997. In 1994, KWH sales to GSU's industrial customers at non-full cost of service rates, which make up approximately 28% of GSU's total industrial class, increased 13%. Sales to the remaining GSU industrial customers increased 2%.

See Note 2 for information with respect to a settlement between System Energy and FERC in which System Energy refunded approximately $61.7 million to AP&L, LP&L, MP&L, and NOPSI, which in turn have made or will make refunds or credits to their customers (except for those portions attributable to AP&L's and LP&L's retained share of Grand Gulf 1 costs). Additionally, System Energy will refund a total of approximately $62 million, plus interest, to AP&L, LP&L, MP&L, and NOPSI over the period through June 2004. AP&L, LP&L, MP&L, and NOPSI also wrote off certain related unamortized balances of deferred investment tax credits.

In the wholesale rate area, FERC approved in 1992, with certain modifications, the proposal of AP&L, LP&L, MP&L, NOPSI, and Entergy Power to sell wholesale power at market-based rates and to provide to electric utilities "open access" to the System's transmission system (subject to certain requirements). GSU was later added to this filing. On October 31, 1994, as amended on January 25, 1995, Entergy Services filed with FERC revised transmission tariffs intended to provide access to transmission service on the same or comparable basis, terms, and conditions as the System operating companies, and the matter is pending. Open access and market pricing, once it takes effect, will increase marketing opportunities for the System, but will also expose the System to the risk of loss of load or reduced revenues due to competition with alternative suppliers.

In March 1994, North Little Rock, Arkansas, awarded AP&L a wholesale power contract that will provide estimated revenues of $347 million over 11 years. Under the contract, the price per KWH was reduced 18%, with increases in price through the year 2004. AP&L, which has been serving North Little Rock for over 40 years, was awarded the contract after intense bidding with several competitors. On May 22, 1994, FERC accepted the contract. Rehearings were requested by one of AP&L's competitors and were held in February 1995. The matter is pending.

In light of the rate issues discussed above, Entergy is aggressively reducing costs to avoid potential earnings erosions that might result as well as to successfully compete by becoming a low-cost producer. In 1994, Entergy announced a restructuring program related to certain of its operating units. This program is designed to reduce costs and improve operating efficiencies. See Note 12 for further information. Also, in response to an increasingly competitive environment, AP&L, LP&L, MP&L, and NOPSI have announced intentions to revise their initial least-cost planning activities and GSU is continuing to work with the PUCT regarding integrated resource planning.

The Energy Policy Act of 1992

The EPAct addresses a wide range of energy issues and is altering the way Entergy and the rest of the electric utility industry operate. The EPAct encourages competition and affords utilities the opportunities and the risks, associated with an open and more competitive market environment. The EPAct creates exemptions from regulation under the Public Utility Holding Company Act of 1935 (Holding Company Act) and creates a class of exempt wholesale generators consisting of utility affiliates and nonutilities that are owners and operators of facilities for the generation and transmission of power for sales at wholesale. The EPAct also gives FERC the authority to order investor-owned utilities, including the System operating companies, to transmit power and energy to or for wholesale purchasers and sellers. The law creates the potential for electric utilities and other power producers to gain increased access to the transmission systems of other entities to facilitate wholesale sales. Both the System operating companies and Entergy Power expect to compete in this market. In addition, the EPAct allows utilities to own and operate foreign generation, transmission, and distribution facilities. See "Nonregulated Investments" below for further information.

Public Utility Holding Company Act of 1935

Entergy Corporation, along with 10 other electric utility holding companies, recently asked Congress to repeal the Holding Company Act. The Holding Company Act requires oversight by the SEC of many business practices and activities of utility holding companies and their subsidiaries including, among other things, nonutility activities. Entergy Corporation believes that the Holding Company Act inhibits its ability to compete in the evolving electric energy marketplace, and largely duplicates the oversight activities already performed by FERC and state and local public service commissions.

Litigation and Regulatory Proceedings

See Note 2 for information on the possible material adverse effects on GSU's financial condition and results of operations as a result of substantial write-offs and/or refunds in connection with outstanding appeals and remands regarding approximately $1.4 billion of abeyed company-wide River Bend plant costs and approximately $187 million ($170 million net of tax) of Texas retail jurisdiction deferred River Bend operating and carrying costs.

See Note 8 for information on the bankruptcy proceedings of Cajun and litigation with Cajun concerning Cajun's ownership interest in River Bend and the related possible material adverse effects on GSU's financial condition.

Entergy Corporation-GSU Merger

The acquisition of GSU by Entergy Corporation was the largest electric utility merger in United States history. Entergy expects to achieve $850 million in fuel cost savings and $670 million in operation and maintenance expense savings over 10 years as a result of the Merger. In 1994, GSU recorded charges associated with certain preacquisition contingencies, severance and augmented retirement costs, and restructuring costs. See Notes 12 and 11 for further information. Although common shareholders experienced some dilution in earnings as a result of the Merger, Entergy believes that the Merger will ultimately be beneficial to common shareholders in terms of strategic benefits as well as economies and efficiencies produced. For further information, see Note 2.

Nonregulated Investments

Entergy Corporation continues to consider opportunities to expand its utility and utility-related businesses that are not regulated by state and local regulatory authorities (nonregulated businesses). Entergy Corporation's investment strategy is to invest in nonregulated business opportunities that have the potential to earn a greater rate of return than its regulated utility operations, and Entergy Corporation may invest up to approximately $150 million per year for the next several years in nonregulated businesses. Entergy Corporation's nonregulated businesses currently fall into two broad categories: power development and new technology related to the utility business. Entergy Corporation made investments in Argentina's and Pakistan's electric energy infrastructures and is also pursuing additional projects in Central America, South America, Europe, and Asia. Entergy Corporation opened an office in Hong Kong during 1994 and expects to open offices in South America and Europe in 1995. Entergy Corporation is negotiating in China to participate in two power generation projects, Datong and Taishan, which are expected to receive final approval in 1995 or 1996. To date, Entergy Corporation has made no investment in the China projects; however, Entergy Corporation's share of these projects may total approximately $115 million. In addition, Entergy Corporation is exploring the possibility to provide telecommunications services that allow customers to control energy usage.

In 1994, Entergy Corporation's nonregulated investments reduced consolidated net income by approximately $31.7 million. In the near term, these investments are unlikely to have a positive effect on earnings; but management believes that these investments will contribute to future earnings growth.

ANO Matters

ANO 2 experienced a forced outage for repair of certain steam generator tubes in March 1992. Further inspections and repairs were conducted at subsequent refueling and mid-cycle outages in September 1992, May 1993, April 1994, and January 1995. AP&L's budgeted maintenance expenditures were adequate to cover the cost of such repairs. ANO 2's output has been reduced 15 megawatts or 1.6% due to secondary side fouling, tube plugging, and reduction of primary temperature. Entergy Operations continues to take steps at ANO 2 to reduce the number and severity of future tube cracks. In addition, Entergy Operations continues to meet with the NRC to discuss such steps and results of inspections of the generator tubes, as well as the timing of future inspections. Additional inspections are planned for the normal refueling outage scheduled for October 1995.

Deregulated Portion of River Bend

As of December 31, 1994, GSU had not recovered a significant amount of its investment in, or received any return associated with, the portion of River Bend included in the deregulated asset plan in Louisiana and the portion of River Bend placed in abeyance as part of the Texas rate order which went into effect in July 1988. See Note 2 for further information. Future earnings will continue to be limited as long as the limited recovery of the investment and lack of return continues.

For the year ended December 31, 1994, GSU recorded revenues resulting from the sale of electricity from the deregulated asset plan of approximately $34.1 million. Operation and maintenance expenses, including fuel, were approximately $30 million, and depreciation expense associated with the deregulated asset plan investment was approximately $16.7 million for the year ended December 31, 1994. For the year ended December 31, 1994, GSU recorded nonfuel revenue of $32.5 million (included in the $34.1 million of total deregulated asset plan revenue discussed above) which, absent the deregulated asset plan, would not have been realized. The operation and maintenance expenses and depreciation expense allocated to the deregulated asset plan as detailed above would have been incurred at River Bend with or without the deregulated asset plan. The future impact of the deregulated asset plan on GSU's results of operations and financial position will depend on River Bend's future operating costs, the unit's efficiency and availability, and the future market for energy over the remaining life of the unit. Based on current estimates of the factors discussed above, GSU anticipates that future revenues from the deregulated asset plan will fully recover all related costs.

Property Tax Exemptions

Exemptions from the payment of Louisiana local property taxes on Waterford 3 and River Bend, which have been in effect for 10 years for each of the plants, will expire in December 1995 and December 1996, respectively. LP&L and GSU are working with taxing authorities to determine the method for calculating the amount of the property taxes to be paid when the exemptions expire. LP&L believes that assessed property taxes will be recovered from its customers through rates. GSU believes that assessed property taxes allocated to its retail jurisdictions will be recovered from those customers through rates.

Environmental Issues

GSU has been notified by the United States Environmental Protection Agency (EPA) that it has been designated as a potentially responsible party for the cleanup of sites on which GSU and others have or have been alleged to have disposed of material designated as hazardous waste. GSU is currently negotiating with the EPA and state authorities regarding the cleanup of some of these sites. Several class action and other suits have been filed in state and federal courts seeking relief from GSU and others for damages caused by the disposal of hazardous waste and for asbestos-related disease allegedly resulting from exposure on GSU premises. While the amounts at issue in the cleanup efforts and suits may be substantial, GSU believes that its results of operations and financial condition will not be materially affected by the outcome of the suits.

During 1993, the Louisiana Department of Environmental Quality issued new rules for solid waste regulation, including waste water impoundments. LP&L has determined that certain of its power plant waste water impoundments are affected by these regulations and has chosen to either upgrade or close them. The aggregate cost of the upgrades and closures, to be completed by 1996, is estimated to be $16 million.

Accounting Issues

Proposed Accounting Standards - The FASB has proposed a SFAS on "Accounting for the Impairment of Long-Lived Assets," effective January 1, 1996. The proposed standard describes circumstances which may result in assets (including goodwill such as the Merger acquisition adjustment, see Note 1) being impaired and provides criteria for recognition and measurement of asset impairment. Note 2 describes regulatory assets of $170 million (net of tax) related to Texas retail deferred River Bend operating and carrying costs. Management believes these deferred costs will be required to be written off under the provisions of the new standard unless there are favorable regulatory or court actions related to these costs prior to the adoption of the new standard by Entergy. Certain other operations of Entergy are potentially affected by this standard, and any resulting write-offs will depend on future operating costs, generating units' efficiency and availability, and the future market for energy over the remaining life of the units. Based on current estimates, Entergy anticipates that future revenues will fully recover the costs of such operations.

Continued Application of SFAS 71 - Entergy's financial statements currently reflect, for the most part, assets and costs based on current cost-based ratemaking regulations, in accordance with SFAS 71, "Accounting for the Effects of Certain Types of Regulation." As discussed above, the electric utility industry is changing and these changes could possibly result in the discontinuance of the application of SFAS 71, which would result in the elimination of regulatory assets and liabilities. See Note 1 for further information.

Accounting for Decommissioning Costs - The FASB is currently reviewing the accounting for decommissioning of nuclear plants. This project could possibly change the System's, as well as the entire utility industry's, accounting for such costs. For further information, see Note 8.

NOTE 1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

The accompanying consolidated financial statements include the accounts of Entergy Corporation and its direct and indirect subsidiaries: AP&L, GSU, LP&L, MP&L, NOPSI, System Energy, Entergy Operations, Entergy Pakistan, Ltd., Entergy Power, Entergy Power Development Corporation, Entergy Richmond Power Corporation, Entergy Services, System Fuels, Entergy Enterprises, Entergy SASI, Entergy S.A., Entergy Argentina S.A., Entergy Transener S.A., Entergy Power Asia, Ltd., Entergy Yacyreta I, Inc., and Entergy Edegel, Inc. Because the acquisition of GSU was consummated on December 31, 1993, under the purchase method of accounting, GSU is included only in the December 31, 1993, consolidated balance sheet amounts. GSU is included in all of the consolidated financial statements for 1994. All references made to Entergy or the System as of, and subsequent to, the Merger closing date include amounts and information pertaining to GSU as an Entergy company. All significant intercompany transactions have been eliminated. Entergy Corporation's utility subsidiaries maintain accounts in accordance with FERC and other regulatory guidelines. Certain previously reported amounts have been reclassified to conform to current classifications.

Revenues and Fuel Costs

The System operating companies accrue estimated revenues for energy delivered since the latest billings. However, prior to January 1, 1993, AP&L, GSU, MP&L, and NOPSI recognized electric and gas revenues when billed. To provide a better matching of revenues and expenses, effective January 1, 1993, AP&L, GSU, MP&L, and NOPSI adopted a change in accounting principle to provide for accrual of estimated unbilled revenues. The cumulative effect of this accounting change as of January 1, 1993, (excluding GSU) increased net income by $93.8 million or $0.54 per share. Had this new accounting method been in effect during prior years, net income before the cumulative effect would not have been materially different from that shown in the accompanying financial statements. In accordance with a LPSC rate order, GSU recorded a deferred credit of $16.6 million for the January 1, 1993, amount of unbilled revenues. See Note 2 regarding recent LPSC rate actions regarding the deferred unbilled revenues.

The System operating companies' rate schedules (except GSU's Texas retail rate schedules) include fuel adjustment clauses that allow either current recovery or deferrals of fuel costs until such costs are reflected in the related revenues. GSU's Texas retail rate schedules include a fixed fuel factor approved by the PUCT, which remains in effect until changed as part of a general rate case, fuel reconciliation, or a fixed fuel factor filing.

Utility Plant

Utility plant is stated at original cost. The original cost of utility plant retired or removed, plus the applicable removal costs, less salvage, is charged to accumulated depreciation. Maintenance, repairs, and minor replacement costs are charged to operating expenses. Substantially all of the utility plant is subject to liens of the subsidiaries' mortgage bond indentures.

Utility plant includes the portions of Grand Gulf 1 and Waterford 3 that were sold and are currently under lease. For financial reporting purposes, these sale and leaseback transactions are reflected as financing transactions.

Total System net electric utility plant in service of $14.5 billion as of December 31, 1994, (excluding approximately $0.5 billion of plant acquisition adjustment related to the Merger) includes $9.8 billion of production plant, $1.4 billion of transmission plant, $2.8 billion of distribution plant, and $0.5 billion of other plant.

Depreciation is computed on the straight-line basis at rates based on the estimated service lives and costs of removal of the various classes of property. Depreciation provisions on average depreciable property approximated 3.0% in 1994 and 1993, and 3.1% in 1992.

AFUDC represents the approximate net composite interest cost of borrowed funds and a reasonable return on the equity funds used for construction. Although AFUDC increases utility plant and increases earnings, it is only realized in cash through depreciation provisions included in rates. The System operating companies' effective composite rates for AFUDC were 9.5% for 1994, 10.6% for 1993, and 10.8% for 1992.

Jointly-Owned Generating Stations

Certain Entergy Corporation subsidiaries own undivided interests in several jointly-owned electric generating facilities and record the investments and expenses associated with these generating stations to the extent of their respective ownership interests. As of December 31, 1994, the System's investment and accumulated depreciation in each of these generating stations were as follows:

Generating Stations		Fuel Type	Total Megawatt Capability	Ownership	Investment	Accumulated Depreciation
					(In Thousands)	
Grand Gulf		Nuclear	1,143	90.00% (1)	$ 3,366,471	$ 751,717
River Bend	Unit 1	Nuclear	936	70.00% (2)	$ 3,080,019	$ 617,002
Independence	Units 1 and 2	Coal	1,678	56.50%	$ 541,893	$ 170,837
White Bluff	Units 1 and 2	Coal	1,660	57.00%	$ 400,918	$ 151,830
Roy S. Nelson	Unit 6	Coal	550	70.00%	$ 390,033	$ 145,897
Big Cajun 2	Unit 3	Coal	540	42.00%	$ 219,788	$ 74,442

(1) Includes System Energy's ownership and leasehold interests in Grand Gulf 1.
(2) See Note 8 regarding the current status of Cajun's 30% undivided ownership interest in River Bend.

Income Taxes

Entergy Corporation and its subsidiaries file a consolidated federal income tax return. Income taxes are allocated to the System companies in proportion to their contribution to consolidated taxable income. SEC regulations require that no Entergy Corporation subsidiary pay more taxes than it would have had a separate income tax return been filed. Deferred taxes are recorded for all temporary differences between book and taxable income. Investment tax credits are deferred and amortized based upon the average useful life of the related property in accordance with rate treatment. As discussed in Note 3, in 1993 Entergy changed its accounting for income taxes to conform with SFAS 109.

Acquisition Adjustment

Entergy Corporation, upon completion of the Merger in December 1993 (see Note 12 for additional details), recorded an acquisition adjustment in utility plant in the amount of $380 million representing the excess of the purchase price over the net assets acquired of GSU. During 1994, the System recorded an additional $115 million of acquisition adjustment related to the resolution of certain preacquisition contingencies and appropriate allocation of purchase price, which combined with the amortization of the acquisition adjustment of $16 million in 1994, resulted in an unamortized balance of $479 million of acquisition adjustment as of December 31, 1994. The

acquisition adjustment is being amortized on a straight-line basis over a 31-year period beginning January 1, 1994, which approximates the remaining average book life of the plant acquired as a result of the Merger. The System anticipates that its future net cash flows will be sufficient to recover such amortization.

Reacquired Debt

The premiums and costs associated with reacquired debt are being amortized over the life of the related new issuances, in accordance with ratemaking treatment.

Cash and Cash Equivalents

Entergy considers all unrestricted highly liquid debt instruments purchased with an original maturity of three months or less to be cash equivalents.

Continued Application of SFAS 71

As a result of the EPAct and actions of regulatory commissions, the electric utility industry is moving toward a combination of competition and a modified regulatory environment. The System's financial statements currently reflect, for the most part, assets and costs based on current cost-based ratemaking regulations, in accordance with SFAS 71, "Accounting for the Effects of Certain Types of Regulation." Continued applicability of SFAS 71 to the System's financial statements requires that rates set by an independent regulator on a cost-of-service basis (including a reasonable rate of return on invested capital) can actually be charged to and collected from customers.

In the event that either all or a portion of a utility's operations cease to meet those criteria for various reasons, including deregulation, a change in the method of regulation or a change in the competitive environment for the utility's regulated services, the utility should discontinue application of SFAS 71 for the relevant portion. That discontinuation should be reported by elimination from the balance sheet of the effects of any actions of regulators recorded as regulatory assets and liabilities.

As of December 31, 1994, and for the foreseeable future, the System's financial statements continue to follow SFAS 71, with the exceptions noted below.

SFAS 101

SFAS 101, "Accounting for the Discontinuation of Application of FASB 71," specifies how an enterprise that ceases to meet the criteria for application of SFAS 71 to all or part of its operations should report that event in its financial statements. GSU discontinued regulatory accounting principles for its wholesale jurisdiction and steam department and the Louisiana deregulated portion of River Bend during 1989 and 1991, respectively.

Fair Value Disclosures

The estimated fair value of financial instruments has been determined by Entergy, using available market information and appropriate valuation methodologies. However, considerable judgment is required in developing the estimates of fair value. Therefore, estimates are not necessarily indicative of the amounts that Entergy could realize in a current market exchange. In addition, gains or losses realized on financial instruments may be reflected in future rates and not accrue to the benefit of stockholders.

Entergy considers the carrying amounts of financial instruments classified as current assets and liabilities to be a reasonable estimate of their fair value because of the short maturity of these instruments. In addition, Entergy does not presently expect that performance of its obligations will be required in connection with certain off-balance sheet commitments and guarantees considered financial instruments. Due to this factor, and because of the related party nature of these commitments and guarantees, determination of fair value is not considered practicable. See Notes 5, 6, and 8 for additional fair value disclosure.

Entergy adopted the provisions of SFAS 115, "Accounting for Certain Investments in Debt and Equity Securities," effective January 1, 1994. As a result, at December 31, 1994, Entergy recorded on the balance sheet a reduction of $2.2 million in decommissioning trust funds, representing the amount by which the fair value of the securities held in such funds is less than amounts for decommissioning recovered in rates and deposited in the funds and the related earnings on the amounts deposited. Due to the regulatory treatment for decommissioning trust funds, the System recorded an offsetting amount in unrealized losses on investment securities as a regulatory asset.

NOTE 2. RATE AND REGULATORY MATTERS

River Bend

In May 1988, the PUCT granted GSU a permanent increase in annual revenues of $59.9 million resulting from the inclusion in rate base of approximately $1.6 billion of company-wide River Bend plant investment and approximately $182 million of related Texas retail jurisdiction deferred River Bend costs (Allowed Deferrals). In addition, the PUCT disallowed as imprudent $63.5 million of company-wide River Bend plant costs and placed in abeyance, with no finding of prudence, approximately $1.4 billion of company-wide River Bend plant investment and approximately $157 million of Texas retail jurisdiction deferred River Bend operating and carrying costs. The PUCT affirmed that the ultimate rate treatment of such amounts would be subject to future demonstration of the prudence of such costs. GSU and intervening parties appealed this order (Rate Appeal) and GSU filed a separate rate case asking that the abeyed River Bend plant costs be found prudent (Separate Rate Case). Intervening parties filed suit in a Texas district court to prohibit the Separate Rate Case. The district court's decision was ultimately appealed to the Texas Supreme Court, which ruled in 1990 that the prudence of the purported abeyed costs could not be relitigated in a separate rate proceeding. The Texas Supreme Court's decision stated that all issues relating to the merits of the original PUCT order, including the prudence of all River Bend-related costs, should be addressed in the Rate Appeal.

In October 1991, the Texas district court in the Rate Appeal issued an order holding that, while it was clear the PUCT made an error in assuming it could set aside $1.4 billion of the total costs of River Bend and consider them in a later proceeding, the PUCT, nevertheless, found that GSU had not met its burden of proof related to the amounts placed in abeyance. The court also ruled that the Allowed Deferrals should not be included in rate base. The court further stated that the PUCT had erred in reducing GSU's deferred costs by $1.50 for each $1.00 of revenue collected under the interim rate increases authorized in 1987 and 1988. The court remanded the case to the PUCT with instructions as to the proper handling of the Allowed Deferrals. GSU's motion for rehearing was denied and, in December 1991, GSU filed an appeal of the October 1991 district court order. The PUCT also appealed the October 1991 district court order, which served to supersede the district court's judgment, rendering it unenforceable under Texas law.

In August 1994, the Texas Third District Court of Appeals (the Appellate Court) affirmed the district court's decision that there was substantial evidence to support the PUCT's 1988 decision not to include the abeyed construction costs in GSU's rate base. While acknowledging that the PUCT had exceeded its authority when it

attempted to defer a decision on the inclusion of those costs in rate base in order to allow GSU a further opportunity to demonstrate the prudence of those costs in a subsequent proceeding, the Appellate Court found that GSU had suffered no harm or lack of due process as a result of the PUCT's error. Accordingly, the Appellate Court held that the PUCT's action had the effect of disallowing the company-wide $1.4 billion of River Bend construction costs for ratemaking purposes. In its August 1994 opinion, the Appellate Court also held that GSU's deferred operating and maintenance costs associated with the allowed portion of River Bend should be included in rate base and that GSU's deferred River Bend carrying costs included in the Allowed Deferrals should also be included in rate base. The Appellate Court's August 1994 opinion affirmed the PUCT's original order in this case.

The Appellate Court's August 1994 opinion was entered by two judges, with a third judge dissenting. The dissenting opinion states that the result of the majority opinion is, among other things, to deprive GSU of due process at the PUCT because the PUCT never reached a finding on the $1.4 billion of construction costs.

In October 1994, the Appellate Court denied GSU's motion for rehearing on the August 1994 opinion as to the $1.4 billion in River Bend construction costs and other matters. GSU appealed the Appellate Court's decision to the Texas Supreme Court, where it is pending.

As of December 31, 1994, the River Bend plant costs disallowed for retail ratemaking purposes in Texas, the River Bend plant costs held in abeyance, and the related operating and carrying cost deferrals totaled (net of taxes) approximately $13 million, $280 million (both net of depreciation), and $170 million, respectively. Allowed Deferrals were approximately $107 million, net of taxes and amortization, as of December 31, 1994. GSU estimates it has collected approximately $158 million of revenues as of December 31, 1994, as a result of the originally ordered rate treatment by the PUCT of these deferred costs. If recovery of the Allowed Deferrals is not upheld, future revenues based upon those allowed deferrals could also be lost, and no assurance can be given as to whether or not refunds of revenue received based upon such deferred costs previously recorded will be required.

No assurance can be given as to the timing or outcome of the remands or appeals described above. Pending further developments in these cases, GSU has made no write-offs or reserves for the River Bend-related costs. Management believes, based on advice from Clark, Thomas & Winters, a Professional Corporation, legal counsel of record in the Rate Appeal, that it is reasonably possible that the case will be remanded to the PUCT, and the PUCT will be allowed to rule on the prudence of the abeyed River Bend plant costs. Rate Caps imposed by the PUCT's regulatory approval of the Merger could result in GSU being unable to use the full amount of a favorable decision to immediately increase rates; however, a favorable decision could permit some increases and/or limit or prevent decreases during the period the Rate Caps are in effect. At this time, management and legal counsel are unable to predict the amount, if any, of the abeyed and previously disallowed River Bend plant costs that ultimately may be disallowed by the PUCT. A net of tax write-off as of December 31, 1994, of up to $293 million could be required based on an ultimate adverse ruling by the PUCT on the abeyed and disallowed costs.

In prior proceedings, the PUCT has held that the original cost of nuclear power plants will be included in rates to the extent those costs were prudently incurred. Based upon the PUCT's prior decisions, management believes that its River Bend construction costs were prudently incurred and that it is reasonably possible that it will recover in rate base, or otherwise through means such as a deregulated asset plan, all or substantially all of the abeyed River Bend plant costs. However, management also recognizes that it is reasonably possible that not all of the abeyed River Bend plant costs may ultimately be recovered.

As part of its direct case in the Separate Rate Case, GSU filed a cost reconciliation study prepared by Sandlin Associates, management consultants with expertise in the cost analysis of nuclear power plants, which supports the reasonableness of the River Bend costs held in abeyance by the PUCT. This reconciliation study

determined that approximately 82% of the River Bend cost increase above the amount included by the PUCT in rate base was a result of changes in federal nuclear safety requirements and provided other support for the remainder of the abeyed amounts.

There have been four other rate proceedings in Texas involving nuclear power plants. Investment in the plants ultimately disallowed ranged from 0% to 15%. Each case was unique, and the disallowances in each were made on a case-by-case basis for different reasons. Appeals of two of these PUCT decisions are currently pending.

The following factors support management's position that a loss contingency requiring accrual has not occurred, and its belief that all, or substantially all, of the abeyed plant costs will ultimately be recovered:

1. The $1.4 billion of abeyed River Bend plant costs have never been ruled imprudent and disallowed by the PUCT.
2. Sandlin Associates' analysis which supports the prudence of substantially all of the abeyed construction costs.
3. Historical inclusion by the PUCT of prudent construction costs in rate base.
4. The analysis of GSU's internal legal staff, which has considerable experience in Texas rate case litigation.

Additionally, management believes, based on advice from Clark, Thomas & Winters, a Professional Corporation, legal counsel of record in the Rate Appeal, that it is reasonably possible that the Allowed Deferrals will continue to be recovered in rates. Management also believes, based on advice from Clark, Thomas & Winters, a Professional Corporation, legal counsel of record in the Rate Appeal, that it is reasonably possible that the deferred costs related to the $1.4 billion of abeyed River Bend plant costs will be recovered in rates to the extent that the $1.4 billion of abeyed River Bend plant is recovered. However, a net of tax write-off of the $170 million of deferred costs related to the $1.4 billion of abeyed River Bend plant costs would be required if they are not allowed to be recovered in rates.

A proposed accounting standard, "Accounting for the Impairment of Long-Lived Assets," which is expected to become effective January 1, 1996, may require the write-off of the $170 million of rate deferrals discussed above, upon adoption of the standard, unless there are favorable regulatory or court actions related to these costs prior to adoption.

Merger-Related Rate Agreements

In November 1993, Entergy Corporation, AP&L, MP&L, and NOPSI entered into separate settlement agreements whereby the APSC, MPSC, and Council agreed to withdraw from the SEC proceeding related to the Merger. In return AP&L, MP&L, and NOPSI agreed, among other things, that their retail ratepayers would be protected from (1) increases in the cost of capital resulting from risks associated with the Merger, (2) recovery of any portion of the acquisition premium or transactional costs associated with the Merger, (3) certain direct allocations of costs associated with GSU's River Bend nuclear unit, and (4) any losses of GSU resulting from resolution of litigation in connection with its ownership of River Bend. AP&L and MP&L agreed not to request any general retail rate increase that would take effect before November 1998, except for, among other things, increases associated with the recovery of certain Grand Gulf 1-related costs, recovery of certain taxes, and force majeure (defined to include, among other things, war, natural catastrophes, and high inflation), and in the case of AP&L, excess capacity costs and costs related to the adoption of SFAS 106 that were previously deferred. MP&L also agreed that retail base rates under the formula rate plan would not be increased above November 1, 1993, levels for a period of five years beginning November 9, 1993 (described below).

In 1993, the LPSC and the PUCT approved separate regulatory proposals that include the following elements: (1) a five-year Rate Cap on GSU's retail electric base rates in the respective states, except for force majeure (defined to include, among other things, war, natural catastrophes, and high inflation); (2) a provision for passing through to retail customers in the respective states the jurisdictional portion of the fuel savings created by the Merger; and (3) a mechanism for tracking nonfuel operation and maintenance savings created by the Merger. The LPSC regulatory plan provides that such nonfuel savings will be shared 60% by the shareholder and 40% by ratepayers during the eight years following the Merger. The LPSC plan requires regulatory filings each year by the end of May through 2001. The PUCT regulatory plan provides that such savings will be shared equally by the shareholder and ratepayers, except that the shareholder's portion will be reduced by $2.6 million per year on a total company basis in years four through eight. The PUCT plan also requires a series of future regulatory filings in November 1996, 1998, and 2001 to ensure that ratepayers' share of such savings be reflected in rates on a timely basis and requires Entergy Corporation to hold GSU's Texas retail customers harmless from the effects of the removal by FERC of a 40% cap on the amount of fuel savings GSU may be required to transfer to other System operating companies under the FERC tracking mechanism (see below). On January 14, 1994, Entergy Corporation filed a request for rehearing of FERC's December 15, 1993, order approving the Merger requesting that FERC restore the 40% cap provision in the fuel cost protection mechanism. The matter is pending.

FERC approved certain rate schedule changes to integrate GSU into the System Agreement. Certain commitments were adopted to provide reasonable assurance that the ratepayers of AP&L, LP&L, MP&L, and NOPSI will not be allocated higher costs, including, among other things, (1) a tracking mechanism to protect AP&L, LP&L, MP&L, and NOPSI from certain unexpected increases in fuel costs, (2) the distribution of profits from power sales contracts entered into prior to the Merger, (3) a methodology to estimate the cost of capital in future FERC proceedings, and (4) a stipulation that AP&L, LP&L, MP&L, and NOPSI will be insulated from certain direct effects on capacity equalization payments should GSU acquire Cajun's 30% share in River Bend (see Note 8).

Formula Rate Plan

Under a formulary incentive rate plan (Formula Rate Plan) effective March 25, 1994, MP&L's earned rate of return is calculated automatically every 12 months and compared to and adjusted against a benchmark rate of return (calculated under a separate formula within the Formula Rate Plan). The Formula Rate Plan allows for periodic small adjustments in rates based on a comparison of earned to benchmark returns and upon certain performance factors. In the same proceeding, the MPSC conducted a general review of MP&L's current rates and on March 1, 1994, issued a final order adopting the Formula Rate Plan and previously agreed-upon stipulations of (1) a required return on equity of 11% and (2) certain accounting adjustments that resulted in a 4.3% ($28.1 million) reduction in MP&L's June 30, 1993, test-year base revenues. The MPSC's order required MP&L to file rates designed to provide for this reduction in operating revenues for the test year on or before March 18, 1994, which became effective March 25, 1994. The final order was appealed to the Mississippi Supreme Court on May 17, 1994, by Mississippi Valley Gas Company (MVG) on the grounds that the MPSC issued the final order without having reviewed the cost of MP&L's promotional practices, some of which MVG alleged to be improper. MVG filed a motion to dismiss the appeal, and on October 28, 1994, the Mississippi Supreme Court granted MVG's motion.

FERC Settlement

In November 1994, FERC approved an agreement settling a long-standing dispute involving income tax allocation procedures of System Energy. In accordance with the agreement, System Energy refunded

approximately $61.7 million to AP&L, LP&L, MP&L, and NOPSI, which in turn have made or will make refunds or credits to their customers (except for those portions attributable to AP&L's and LP&L's retained share of Grand Gulf 1 costs). Additionally, System Energy will refund a total of approximately $62 million, plus interest, to AP&L, LP&L, MP&L, and NOPSI over the period through June 2004. The settlement also required the write-off of certain related unamortized balances of deferred investment tax credits by AP&L, LP&L, MP&L, and NOPSI. The settlement reduced Entergy Corporation's consolidated net income for the year ended December 31, 1994, by approximately $68.2 million, offset by the write-off of the unamortized balances of related deferred investment tax credits of approximately $69.4 million ($2.9 million for Entergy Corporation; $27.3 million for AP&L; $31.5 million for LP&L; $6 million for MP&L; and $1.7 million for NOPSI). System Energy also reclassified from utility plant to other deferred debits approximately $81 million of other Grand Gulf 1 costs. Although excluded from rate base, System Energy will be permitted to recover such costs over a 10-year period. Interest on the $62 million refund and the loss of the return on the $81 million of other Grand Gulf 1 costs will reduce Entergy's and System Energy's net income by approximately $10 million annually over the next 10 years.

As a result of the charges associated with the settlement, System Energy obtained the consent of certain banks (parties to the Reimbursement Agreement) to waive temporarily the fixed charge coverage covenant in the letters of credit and Reimbursement Agreement related to the Grand Gulf 1 sale and leaseback transaction until November 30, 1995. System Energy expects that upon expiration of the waiver period, it will be in compliance with the fixed charge coverage covenant. Absent a waiver, System Energy's failure to perform this covenant could cause a draw under the letters of credit and/or early termination of the letters of credit. If the letters of credit were not replaced in a timely manner, a default or early termination of System Energy's leases could result.

Rate Deferrals

The System operating companies have various rate moderation or phase-in plans that reduced the immediate effect of Grand Gulf 1, River Bend, and Waterford 3 costs on ratepayers. Under these plans, certain costs are either retained permanently (and not recovered from ratepayers), deferred in early years and collected in later years, or recovered currently from customers. These plans vary in the proportions of costs each company retains, defers, or recovers and in the length of the deferral/recovery periods. Only those costs retained permanently and not recovered through rates or through sales to third parties result in a reduction of net income. The carrying charges associated with unamortized deferrals were either deferred or recovered currently from customers.

GSU deferred approximately $369 million of River Bend operating costs, purchased power costs, and accrued carrying charges pursuant to a 1986 PUCT accounting order. Approximately $182 million of these costs are being amortized over a 20-year period, and the remaining $187 million are not being amortized pending the ultimate outcome of the Rate Appeal. As of December 31, 1994, the unamortized balance of these costs was $321 million. Further, GSU deferred approximately $400.4 million of similar costs pursuant to a 1986 LPSC accounting order. These costs, of which approximately $122 million were unamortized as of December 31, 1994, are being amortized over a 10-year period ending in 1997.

In accordance with a phase-in plan approved by the LPSC, GSU deferred $294 million of its River Bend costs related to the period February 1988 through February 1991. GSU has amortized $129 million through December 31, 1994, and the remainder of $165 million will be recovered over approximately 3.2 years.

AP&L's permanently retained share of Grand Gulf 1 costs is 7.92% in 1994 and all succeeding years of the unit's commercial operation. In the event AP&L is not able to sell its retained share to third parties, it may sell such energy to its retail customers at a price equal to its avoided energy cost, which is currently less than AP&L's cost of such energy. LP&L permanently absorbs 18% of its 14% (approximately 2.52%) FERC-allocated share of

Grand Gulf 1-related costs. LP&L is able to recover through the fuel adjustment clause 4.6 cents per KWH (as of May 1994) for the energy related to its retained portion of these costs. Alternatively, LP&L may sell such energy to nonaffiliated parties at prices above the fuel adjustment clause recovery amount, subject to LPSC approval. For the year ended December 31, 1994, System Energy's billings for Grand Gulf 1-related costs totaled approximately $475 million. A deregulated asset plan representing an unregulated portion (approximately 22%) of River Bend (plant costs, generation, revenues, and expenses) was established pursuant to a January 1992 LPSC order. The plan allows GSU to sell such generation to Louisiana retail customers at 4.6 cents per KWH or off-System at higher prices with certain sharing provisions for such incremental revenue. Based on current estimates, Entergy anticipates that future revenues will fully recover all related costs.

Filings with the PUCT and Texas Cities

In March 1994, the Texas Office of Public Utility Counsel and certain cities served by GSU instituted an investigation of the reasonableness of GSU's rates. In June 1994, GSU provided the cities with information that GSU believed supported the current rate level. GSU filed the same information with the PUCT in June 1994, pursuant to provisions of the Merger. In September 1994, various cities adopted ordinances directing GSU to reduce its Texas retail rates by $45.9 million. GSU appealed the cities' ordinances to the PUCT for a determination of reasonableness of GSU's rates.

In November 1994, those cities that intervened in the PUCT appeal filed testimony with the PUCT supporting a $118 million base rate reduction in lieu of the previously proposed $45.9 million reduction. In November 1994, the PUCT staff filed testimony that supported a $38.2 million base rate reduction. GSU filed information with the PUCT that it believed supported the current level of rates. Hearings were held in December 1994 and on March 20, 1995, the PUCT ordered a $72.9 million annual base rate reduction for the period March 31, 1994, through September 1, 1994, decreasing to an annual base rate reduction of $52.9 million after September 1, 1994. In accordance with the Merger agreement, the rate reduction is applied retroactively to March 31, 1994. As a result, GSU recorded a $57 million reserve for rate refund in 1994. The rate reduction is being appealed and no assurance can be given as to the timing or outcome of the appeal.

Texas Cities Rate Settlement - 1993

In June 1993, 13 cities within GSU's Texas service area instituted an investigation to determine whether GSU's current rates were justified. In October 1993, the general counsel of the PUCT instituted an inquiry into the reasonableness of GSU's rates. In November 1993, a settlement agreement was filed with the PUCT which provided for an initial reduction in GSU's annual retail base revenues in Texas of approximately $22.5 million effective for electric usage on or after November 1, 1993, and a second reduction of $20 million effective September 1994. Pursuant to the settlement, GSU reduced rates with a $20 million one-time bill credit in December 1993, and refunded approximately $3 million to Texas retail customers on bills rendered in December 1993. The PUCT approved the settlement agreement on July 21, 1994. The cities' rate inquiries were settled earlier on the same terms.

LPSC Rate Reviews

In May 1994, GSU made the required first post-Merger earnings analysis filing with the LPSC. On December 14, 1994, the LPSC ordered a $12.7 million annual rate reduction for GSU effective January 1995. The rate order included, among other things, a reduction in GSU's Louisiana jurisdictional authorized return on equity from 12.75% to 10.95% and the amortization for the benefit of the customer of $8.3 million of previously deferred unbilled revenue, representing one-half of the total resulting from a change in accounting as discussed in Note 1.

On December 28, 1994, GSU received a preliminary injunction from the 19th Judicial District Court regarding $8.3 million of the reduction. On January 1, 1995, GSU reduced rates by $4.4 million. The entire $12.7 million reduction is being appealed and no assurance can be given as to the timing or outcome of the appeal.

In August 1994, LP&L filed a performance-based formula rate plan with the LPSC. The proposed formula rate plan would continue existing LP&L rates at current levels, while providing financial incentive to reduce costs and maintain high levels of customer satisfactic and system reliability. A performance rating adjustment feature of the plan would allow LP&L the opportu to earn a higher rate of return if it improves performance over time. Conversely, if performance declines, th te of return LP&L could earn would be lowered. This provides financial incentive for LP&L to maintain continuous improvement in all three performance categories (customer price, customer satisfaction, and customer reliability). Under the proposed plan, if LP&L's earnings fall within a bandwidth around a benchmark rate of return, there would be no adjustment in rates. If LP&L's earnings are above the bandwidth, the proposed plan would automatically reduce LP&L's base rates. Alternatively, if LP&L's earnings are below the bandwidth, the proposed plan would automatically increase LP&L's base rates. The reduction or increase in base rates would be an amount representing 50% of the difference between the earned rate of return and the nearest limit of the bandwidth. In no event would the annual adjustment in rates exceed 2% of LP&L's retail revenues. Hearings were held in March 1995. No assurance can be given that the LPSC will accept the performance-based formula rate plan, or that the current rate review will not result in a rate decrease.

February 1994 Ice Storm/Rate Rider

In early February 1994, an ice storm left more than 221,000 Entergy customers without electric power across the System's four-state service area. The storm was the most severe natural disaster ever to affect the System, causing damage to transmission and distribution lines, equipment, poles, and facilities in certain areas, primarily in Mississippi. Repair costs totaled approximately $116.2 million, $30.8 million, and $77.2 million for the System, AP&L, and MP&L, respectively, with $85 million, $18.7 million, and $64.6 million of these amounts capitalized as plant-related costs. The remaining balances have been charged against the respective companies' regulatory storm damage reserves, except for MP&L which recorded a deferred debit. On April 15, 1994, MP&L filed for rate recovery of costs related to the ice storm. MP&L's filing, as subsequently amended, requested recovery of the revenue requirement associated with MP&L's ice storm costs recorded through April 30, 1994, representing approximately 86% of the total estimated ice storm costs. MP&L may make another ice storm rate filing with the MPSC during 1995 to recover ice storm costs recorded by MP&L after April 30, 1994. In August 1994, MP&L and the MPSC's Public Utilities Staff entered into a stipulation with respect to the recovery of ice storm costs recorded through April 30, 1994, and in September 1994, the MPSC approved the stipulation. Under the stipulation, MP&L implemented an ice storm rider schedule, which went into effect on September 29, 1994, that will increase rates approximately $8 million annually for five years. At the end of the five-year period, the revenue requirement associated with the undepreciated ice storm capitalized costs will be included in MP&L's base rates to the extent that this revenue requirement does not result in MP&L's rate of return on rate base being above the benchmark rate of return under MP&L's formula rate plan.

PUCT Fuel Cost Review (December 1, 1986 - September 30, 1991)

In January 1992, GSU applied to the PUCT for a new fixed fuel factor and requested a final reconciliation of fuel and purchased power costs incurred between December 1, 1986, and September 30, 1991. GSU proposed to recover net underrecoveries and interest (including underrecoveries related to Nelson Industrial Steam Company (NISCO), discussed below) over a 12-month period.

In April 1993, the presiding PUCT administrative law judge (ALJ) issued a report concluding that GSU incurred approximately $117 million of nonreimbursable fuel costs on a company-wide basis (approximately $50 million on a Texas retail jurisdictional basis) during the reconciliation period. Included in the nonreimbursable fuel costs were payments above GSU's avoided cost rate for power purchased from NISCO. The PUCT ordered in 1986 that the purchased power costs from NISCO in excess of GSU's avoided costs be disallowed. The PUCT disallowance resulted in approximately $12 million to $15 million of unrecovered purchased power costs on an annual basis, which GSU continued to expense as the costs were incurred. In April 1991, the Texas Supreme Court, in the appeal of such order, ordered the PUCT to allow GSU to recover purchased power payments in excess of its avoided cost in future proceedings, if GSU established to the PUCT's satisfaction that the payments were reasonable and necessary expenses.

In June 1993, the PUCT concluded that the purchased power payments made to NISCO in excess of GSU's avoided cost were not reasonably incurred. As a result of the order, GSU recorded additional fuel expenses (including interest) of $2.8 million for non-NISCO related items. The PUCT's order resulted in no additional expenses related to the NISCO issue, or for overcollections related to the fixed fuel factor, as those charges were expensed by GSU as they were incurred. The PUCT concluded that GSU had over-collected its fuel costs in Texas and ordered GSU to refund approximately $33.8 million to its Texas retail customers, including approximately $7.5 million of interest. In that proceeding, the PUCT also set GSU's fixed fuel factor in Texas at 1.84 cents per KWH in response to GSU's request that the factor be set at 2.02 cents per KWH. In October 1993, GSU appealed the PUCT's order to the Travis County District Court where the matter is still pending. No assurance can be given as to the timing or outcome of that appeal. In a subsequent proceeding to review GSU's fuel factor, the PUCT approved GSU's request to further reduce its fixed fuel factor in Texas to 1.78 cents per KWH from 1.84 cents per KWH.

PUCT Fuel Cost Review (October 1, 1991 - December 31, 1993)

On January 9, 1995, GSU and various parties reached an agreement for the reconciliation of over- and under-recovery of fuel and purchased power expenses for the period October 1, 1991, through December 31, 1993. While the settlement still requires PUCT approval, GSU believes it will ultimately be approved and has accordingly recorded a reserve of $7.6 million.

LPSC Fuel Cost Review

In November 1993, the LPSC ordered a review of GSU's fuel costs for the period October 1988 through September 1991 (Phase I) based on the number of outages at River Bend and the findings in the June 1993 PUCT fuel reconciliation case. In July 1994, the LPSC ruled in the Phase I fuel review case and ordered GSU to refund approximately $27 million to its customers. Under the order, a refund of $13.1 million, which was not contested under a Louisiana Supreme Court decision as discussed below, was made through a billing credit on August 1994 bills. In August 1994, GSU appealed the remaining portion of the LPSC-ordered refund to the district court. GSU has made no reserve for the remaining portion, pending outcome of the district court appeal, and no assurance can be given as to the timing or outcome of the appeal.

On January 18, 1995, GSU met with the special counsel of the LPSC to discuss the procedural schedule for the upcoming fuel review (Phase II). The period under investigation was determined to be from October 1991 to December 1994. Hearings are scheduled to begin in July 1995.

In February 1990, the LPSC disallowed the pass-through to ratepayers for the portion of GSU's cost to purchase power from NISCO representing the excess of NISCO's purchase price of the units over GSU's

depreciated cost of the units. GSU appealed the 1990 order. In March 1994, the Louisiana Supreme Court ruled in favor of the LPSC. In 1994, GSU recorded an estimated refund provision of $13.1 million, before related income taxes of $5.3 million.

1994 NOPSI Settlement

In a settlement with the Council that was approved on December 29, 1994, NOPSI agreed to reduce electric and gas rates and issue credits and refunds to customers. Effective January 1, 1995, NOPSI implemented a $31.8 million permanent reduction in electric base rates and a $3.1 million permanent reduction in gas base rates. These adjustments resolved issues associated with NOPSI's return on equity exceeding 13.76% for the test year ended September 30, 1994. Under the 1991 NOPSI Settlement, NOPSI is recovering from its retail customers its allocable share of certain costs related to Grand Gulf 1. NOPSI's base rates to recover those costs were derived from estimates of those costs made at that time. Any overrecovery of costs is required to be returned to customers. Grand Gulf 1 has experienced lower operating costs than previously estimated, and NOPSI accordingly is reducing its base rates in two steps to more accurately match the current costs related to Grand Gulf 1. On January 1, 1995, NOPSI implemented a $10 million permanent reduction in base electric rates to reflect the reduced costs related to Grand Gulf 1, to be followed by an additional $4.4 million rate reduction on October 31, 1995. These Grand Gulf 1 rate reductions, which are expected to be largely offset by lower operating costs, may reduce NOPSI's after-tax net income by approximately $1.4 million per year beginning November 1, 1995. The next scheduled Grand Gulf 1 phase-in rate increase in the amount of $4.4 million on October 31, 1995, will not be affected by the 1994 NOPSI Settlement.

The 1994 NOPSI Settlement also requires NOPSI to credit its customers $25 million over a 21-month period, beginning January 1, 1995, in order to resolve disputes with the Council regarding the interpretation of the 1991 NOPSI Settlement. NOPSI reduced its revenues by $25 million and recorded a $15.4 million net-of-tax reserve associated with the credit in the fourth quarter of 1994. The 1994 NOPSI Settlement further required NOPSI to refund, in December 1994, $13.3 million of credits previously scheduled to be made to customers during the period January 1995 through July 1995. These credits were associated with a July 7, 1994, Council resolution that ordered a $24.95 million rate reduction based on NOPSI's overearnings during the test year ended September 30, 1993. Accordingly, NOPSI recorded an $8 million net-of-tax charge in the fourth quarter of 1994.

The 1994 NOPSI Settlement also required NOPSI to refund $9.3 million of overcollections associated with Grand Gulf 1 operating costs, and $10.5 million of refunds associated with the settlement by System Energy of a FERC tax audit. The settlement of the FERC tax audit by System Energy required refunds to be passed on to NOPSI and to other Entergy subsidiaries and then on to customers. These refunds have no effect on current period net income.

NOTE 3. INCOME TAXES

Income tax expense consisted of the following:

	For the Years Ended December 31,		
	1994	1993	1992
		(In Thousands)	
Current:			
Federal	$227,046	$236,513	$ 99,898
State	50,300	30,618	23,596
Total	277,346	267,131	123,494
Deferred - net:			
Reclassification due to net operating loss carryforward	48,482	(17,131)	35,969
Rate deferrals - net	(137,376)	(88,651)	(54,079)
Gas contract settlement	5,483	9,513	15,180
Liberalized depreciation	127,881	116,513	107,976
Unbilled revenue	7,246	56,315	(18,902)
Alternative minimum tax	(614)	(10,270)	6,577
Bond reacquisition cost	(4,481)	17,958	11,496
Nuclear refueling and maintenance	552	(7,929)	9,740
Decontamination and decommissioning fund	2,366	27,303	-
Provision for rate refunds	(31,739)	-	-
FERC Settlement	(23,098)	-	-
Adjustment to Grand Gulf 2 tax basis	(14,037)	-	-
Other	(35,094)	15,035	(1,595)
Total	(54,429)	118,656	112,362
Investment tax credit adjustments - net	(24,739)	(43,796)	20,607
Investment tax credit amortization - FERC settlement	(66,454)	-	-
Recorded income tax expense	$131,724	$341,991	$256,463
Charged to operations	$131,965	$251,163	$210,081
Charged to other income	(241)	33,640	46,382
Charged to cumulative effect	-	57,188	-
Recorded income tax expense	131,724	341,991	256,463
Income taxes applied against the debt component of AFUDC	-	-	696
Total income taxes	$131,724	$341,991	$257,159

Total income taxes differ from the amounts computed by applying the statutory federal income tax rate to income before taxes. The reasons for the differences were:

	For the Years Ended December 31					
	1994		1993		1992	
	Amount	% of Pretax Income	Amount	% of Pretax Income	Amount	% of Pretax Income
	(Dollars in Thousands)					
Computed at statutory rate	$194,448	35.0	$332,555	35.0	$257,461	34.0
Increases (reductions) in tax resulting from:						
Amortization of excess deferred income taxes	(5,845)	(1.1)	(7,063)	(0.7)	(6,537)	(0.9)
State income taxes net of federal income tax effect	13,766	2.5	30,160	3.2	26,057	3.5
Amortization of investment tax credits	(27,337)	(4.9)	(25,911)	(2.7)	(26,885)	(3.6)
Investment tax credit amortization - FERC Settlement	(66,454)	(12.0)	-	-	-	-
Depreciation	9,995	1.8	5,925	0.6	4,527	0.6
SFAS 109 adjustment	-	-	9,547	1.0	-	-
Other - net	13,151	2.4	(3,222)	(0.4)	1,840	0.3
Recorded income tax expense	131,724	23.7	341,991	36.0	256,463	33.9
Income taxes applied against debt component of AFUDC	-	-	-	-	696	0.1
Total income taxes	$131,724	23.7	$341,991	36.0	$257,159	34.0

Significant components of net deferred tax liabilities as of December 31, 1994 and 1993, were:

	1994	1993
	(In Thousands)	
Deferred tax liabilities:		
Net regulatory assets	$(1,645,119)	$(1,676,161)
Plant-related basis differences	(3,092,889)	(2,945,933)
Rate deferrals	(617,699)	(767,124)
Other	(181,743)	(167,478)
Total	$(5,537,450)	$(5,556,696)
Deferred tax assets:		
Sale and leaseback	$ 247,842	$ 241,391
Accumulated deferred investment tax credit	227,473	330,852
Alternative minimum tax credit	137,387	138,063
Removal cost	88,052	92,618
Standard coal plant	29,275	30,165
NOL carryforwards	251,000	307,737
Pension-related items	30,040	24,879
Unbilled revenues	25,328	23,587
Provision for rate refunds	37,838	-
Investment tax credit carryforwards	190,987	314,862
Other	316,777	149,568
Total	$ 1,581,999	$ 1,653,722
Net deferred tax liabilities	$(3,955,451)	$(3,902,974)

As of December 31, 1994, Entergy had federal net operating loss (NOL) carryforwards of $666.7 million and state NOL carryforwards of $498.2 million related to GSU operations. Investment tax credit (ITC) and other credit carryforwards, as of December 31, 1994, amounted to $282.6 million. The ITC carryforwards include the 35% reduction required by the Tax Reform Act of 1986 and may be applied against federal income tax liabilities and, if not utilized, will expire between 1995 and 2003. It is currently anticipated that approximately $64.4 million will expire unutilized. A valuation allowance has been provided for deferred tax assets relating to that amount. The alternative minimum tax (AMT) credit carryforwards as of December 31, 1994, were $137.4 million. This AMT credit can be carried forward indefinitely and will reduce the System's federal income tax liability in the future.

In accordance with the System Energy FERC Settlement, the System wrote off $66.5 million of unamortized deferred investment tax credits in 1994.

In 1993, the System adopted SFAS 109. SFAS 109 required that deferred income taxes be recorded for all temporary differences and carryforwards, and that deferred tax balances be based on enacted tax laws at tax rates that are expected to be in effect when the temporary differences reverse. SFAS 109 required that regulated enterprises recognize adjustments resulting from implementation as regulatory assets or liabilities if it is probable that such amounts will be recovered from or returned to customers in future rates. A substantial majority of the adjustments required by SFAS 109 was recorded to deferred tax balance sheet accounts with offsetting adjustments to regulatory assets and liabilities. As a result of the adoption of SFAS 109, 1993 net income and earnings per share were decreased by $13.2 million and $0.08 per share, respectively, and assets and liabilities were increased

by $822.7 million and $835.9 million, respectively. The cumulative effect of the adoption of SFAS 109 is included in income tax expense charged to operations.

In August 1994, Entergy received an Internal Revenue Service report covering the federal income tax audit of Entergy Corporation and subsidiaries for the years 1988 - 1990. The report asserts an $80 million tax deficiency for the 1990 consolidated federal income tax returns related primarily to the application of accelerated investment tax credits associated with Waterford 3 and Grand Gulf nuclear plants. Entergy believes there is no material tax deficiency and is vigorously contesting the proposed assessment.

NOTE 4. LINES OF CREDIT AND RELATED BORROWINGS

The SEC has authorized AP&L, GSU, LP&L, MP&L, NOPSI, and System Energy to effect short-term borrowings up to an aggregate of $664 million, which may be increased to as much as $1.216 billion (subject to individual authorizations for each company) after further SEC approval. These authorizations are effective through November 30, 1996. As of December 31, 1994, AP&L, GSU, LP&L, MP&L, NOPSI, and System Energy had total outstanding borrowings of $91.8 million (including $8 million under the Money Pool arrangement). Short-term borrowings by MP&L and NOPSI are also limited by the terms of their respective G&R Bond indentures to amounts not exceeding the greater of 10% of capitalization or 50% of Grand Gulf 1 rate deferrals available to support the issuance of G&R Bonds.

As of December 31, 1994, GSU had unused lines of credit for short-term borrowings of $5 million from banks within its service territories. Entergy Services has bank lines of credit permitting it to borrow up to $70 million, of which $65 million in borrowings was outstanding as of December 31, 1994. Interest rates associated with AP&L, Entergy Services, GSU, LP&L, and MP&L's lines of credit generally are based on the prime rate, the EURO dollar rate, a certificate of deposit rate, the London interbank offered rate, or a bid rate. Commitment fees on these lines of credit are 0.125% of the amount of available credit. In addition, AP&L, GSU, LP&L, MP&L, NOPSI, System Energy, Entergy Operations, Entergy Services, and System Fuels can borrow from each other and from Entergy Corporation through the Money Pool, an intra-System borrowing arrangement designed to reduce the System's dependence on external short-term borrowings.

Entergy Corporation has requested, but not yet received, SEC approval for a $300 million three-year bank line of credit. System Fuels has financing agreements with banks permitting it to borrow up to $65 million, of which $23 million in borrowings was outstanding as of December 31, 1994. Borrowings under System Fuels' financing agreements are restricted as to use, and are secured by fuel inventories and certain accounts receivable from the sales of these inventories.

NOTE 5. PREFERRED, PREFERENCE, AND COMMON STOCK

The number of shares and dollar value of the System operating companies' preferred and preference stock were:

	As of December 31,				
	Shares Authorized and Outstanding		Total Dollar Value		Call Price Per Share as of December 31,
	1994	1993	1994	1993	1994
			(Dollars in Thousands)		
Preference Stock					
Cumulative, without par value					
7% Series (1)(2)	6,000,000	6,000,000	$150,000	$150,000	-
Preferred Stock					
Without sinking fund:					
Cumulative, $100 par value					
4.16% - 5.56% Series	1,201,715	1,201,715	$120,172	$120,172	$102.50 to $108.00
6.08% - 8.56% Series	2,262,829	2,262,829	226,283	226,283	$101.80 to $103.78
9.16% - 11.48% Series	425,000	425,000	42,500	42,500	$104.06 to $104.64
Cumulative, $25 par value					
8.00% - 9.68% Series	3,880,000	3,880,000	97,000	97,000	$26.56
Cumulative, $0.01 par value					
$2.40 Series (1)(2)	2,000,000	2,000,000	50,000	50,000	-
$1.96 Series (1)(2)	600,000	600,000	15,000	15,000	-
Total without sinking fund	10,369,544	10,369,544	$550,955	$550,955	
With sinking fund:					
Cumulative, $100 par value					
7.00% - 9.76% Series	1,935,372	2,126,539	$193,537	$212,654	$100.00 to $106.75
12.0[illegible] - 15.44% Series	72,195	117,195	7,219	11,720	$106.00 to $107.72
Adjustable, 7.10% - 7.15% as of December 31, 1993	519,000	553,500	51,900	55,350	$100.00 to $103.00
Cumulative, $25 par value					
9.92% - 12.64% Series	1,691,666	2,311,666	42,290	57,791	$25.67 to $27.37
13.28% Series	200,000	461,537	5,000	11,538	$28.22
Total with sinking fund	4,418,233	5,570,437	$299,946	$349,053	

(1) The total dollar value represents the involuntary liquidation value of $25 per share.
(2) These series are not redeemable as of December 31, 1994.

The fair value of the System operating companies' preferred and preference stock with sinking fund was estimated to be approximately $437.4 million and $526.2 million as of December 31, 1994 and 1993, respectively. The fair values were determined using quoted market prices or estimates from nationally recognized investment banking firms. See Note 1 for additional information on disclosure of fair value of financial instruments.

Changes in the preferred stock of AP&L, GSU, LP&L, MP&L, and NOPSI with and without sinking fund during the last three years were (excluding GSU in 1992):

	Number of Shares		
	1994	1993	1992
Preferred Stock Issuances:			
$100 par value	-	-	700,000
$25 par value	-	-	1,480,000
$0.01 par value	-	-	600,000
Preferred Stock Retirements:			
$100 par value	(270,667)	(265,000)	(589,940)
$25 par value	(881,537)	(1,180,000)	(1,895,160)

Cash sinking fund requirements for the next five years for preferred stock outstanding as of December 31, 1994, are (in millions): 1995 - $38.8, 1996 - $23.3, 1997 - $22.6, 1998 - $15.3, and 1999 - $64.8.

On December 31, 1993, Entergy Corporation issued 56,695,724 shares of common stock in connection with the Merger. In addition, Entergy Corporation redeemed 174,552,011 shares of $5 par value common stock and reissued 174,552,011 shares of $0.01 par value common stock resulting in an increase in paid-in capital of $871 million.

Entergy Corporation has a program to repurchase shares of its outstanding common stock. The timing and amount of such repurchases depend upon market conditions and authorization from the Board of Directors of Entergy Corporation (Board). Under this program, Entergy Corporation repurchased and retired (returned to authorized but unissued status) 1,230,000 shares at a cost of $30.7 million in 1994, and 3,671,900 shares at a cost of $161.6 million in 1992. No shares were repurchased under the program in 1993. In addition, 2,805,000 shares, 627,000 shares, and 1,943 shares of treasury stock were purchased for cash during 1994, 1993, and 1992, respectively, at a cost of $88.8 million, $20.6 million, and $0.1 million, respectively. A portion of the treasury shares purchased in 1993 were subsequently reissued and in connection with the Merger on December 31, 1993, all of the existing balance of 579,274 shares of treasury shares was canceled. On December 9, 1994, the Board approved the repurchase of common shares for an aggregate consideration of not in excess of $300 million during the period through January 1996.

Entergy Corporation has SEC authorization to acquire up to 3,000,000 shares of its common stock to be held as treasury shares and to be reissued to meet the requirements of the Stock Plan for Outside Directors (Directors' Plan), the Equity Ownership Plan of Entergy Corporation and Subsidiaries (Equity Plan), and certain other stock benefit plans. The Directors' Plan awards nonemployee directors a portion of their compensation in the form of a fixed number of shares of Entergy Corporation common stock. Shares awarded under the Directors' Plan were 18,757, 12,550 and 14,904 during 1994, 1993, and 1992, respectively. The Equity Plan grants stock options, restricted shares, and equity awards to key employees of the System companies. The costs of awards are charged to income over the period of the grant or restricted period, as appropriate. Amounts charged to compensation expense in 1994 were immaterial. Stock options, which comprise 59% of the shares targeted for distribution under the Equity Plan, are granted at exercise prices not less than market value on the date of grant. The options are generally exercisable no less than six months nor more than 10 years after the date of grant.

Nonstatutory stock options transactions are summarized as follows:

	Option Price	Number of Options
Options granted during 1992	29.625	50,000
Options exercised during 1992	29.625	(5,000)
Options granted during 1993:	34.75	70,000
	39.75*	6,107
Options exercised during 1993:	29.625	(13,198)
	34.75	(5,000)
Options granted during 1994	37.00	67,500
Options exercised during 1994	-	-
Options remaining as of December 31, 1994		170,409

* Options are not currently exercisable at December 31, 1994.

Entergy Corporation received SEC authorization in 1994 to issue new shares for the Employee Stock Investment Plan (ESIP) or to acquire, through March 31, 1997, up to 2,000,000 shares of its common stock to be held as treasury shares and reissued to meet the requirements of the ESIP. Under the ESIP, employees may be granted the opportunity to purchase, (for up to 10% of their regular annual salary, (but not more than $25,000)), common stock at 85% of the market value on the first or last business day of the plan year, whichever is lower. The 1994 plan year runs from April 1, 1994, to March 31, 1995.

NOTE 6. LONG-TERM DEBT

The long-term debt of Entergy Corporation's subsidiaries as of December 31, 1994 and 1993, was:

Maturities		Interest Rates			
From	To	From	To	1994	1993
				(In Thousands)	
First Mortgage Bonds					
1995	1999	4-5/8%	14%	$1,290,210	$1,354,810
2000	2004	6%	11%	1,282,320	1,143,520
2005	2009	6.65%	10%	335,000	635,000
2015	2019	9-5/8%	11-3/8%	90,319	90,319
2020	2024	7%	10-3/8%	1,083,818	1,083,818
G&R Bonds					
1995	1999	5.95%	14.95%*	221,200	284,200
2000	2023	6-5/8%	8.65%	375,000	350,000
Governmental Obligations **					
1992	2008	6.125%	10%	142,622	139,009
2009	2023	5.95%	12.5%	1,499,768	1,481,678
Debentures - Due 1998, 9.72%				200,000	200,000
Long-Term DOE Obligation (Note 8)				105,163	101,029
Waterford 3 Lease Obligation, 8.76% (Note 9)				353,600	353,600
Grand Gulf Lease Obligation, 7.02% (Note 9)				500,000	500,000
Other Long-Term Debt				6,879	6,879
Unamortized Premium and Discount - Net				(43,341)	(45,890)
Total Long-Term Debt				7,442,558	7,677,972
Less Amount Due Within One Year				349,085	322,010
Long-Term Debt Excluding Amount Due Within One Year				$7,093,473	$7,355,962

* $20 million of the 14.95% Series G&R Bonds and $9.2 million of the 13.9% Series G&R Bonds were due 2/1/95. All other series are at interest rates within the range of 5.95% - 11.2%

** Consists of pollution control bonds, certain series of which are secured by non-interest bearing first mortgage bonds.

The fair value of Entergy Corporation's long-term debt, excluding lease obligations and long-term DOE obligations, as of December 31, 1994 and 1993, was estimated to be $6.293 billion and $7.207 billion, respectively. The fair values were determined using bid prices reported by dealer markets and by nationally recognized investment banking firms.

For the years 1995, 1996, 1997, 1998, and 1999, Entergy Corporation's subsidiaries have long-term debt maturities (excluding lease obligations) and cash sinking fund requirements aggregating (in millions) $349.1, $558.0, $361.3, $314.9, and $172.4, respectively. In addition, other sinking fund requirements will be satisfied by cash or by certification of property additions at the rate of 167% of such requirements. The amounts associated with this provision total approximately $20.9 million for each of the years 1995 through 1999.

NOTE 7. DIVIDEND RESTRICTIONS

Various agreements relating to the long-term debt and preferred stock of Entergy Corporation's subsidiaries restrict the payment of cash dividends or other distributions on their common stock. In addition to these restrictions, the Holding Company Act prohibits Entergy Corporation's subsidiaries from making loans or advances to Entergy Corporation. As of December 31, 1994, Entergy Corporation's subsidiaries had restricted common equity of approximately $4.495 billion, including $497 million of restricted retained earnings, which were unavailable for distribution to Entergy Corporation. In February 1995, Entergy Corporation received common stock dividend payments from its subsidiaries totaling $96.8 million.

NOTE 8. COMMITMENTS AND CONTINGENCIES

Cajun - River Bend

GSU has significant business relationships with Cajun, including co-ownership of River Bend and Big Cajun 2, Unit 3. GSU and Cajun own 70% and 30% undivided interests in River Bend, respectively, and 42% and 58% undivided interests in Big Cajun 2, Unit 3, respectively.

In June 1989, Cajun filed a civil action against GSU in the United States District Court for the Middle District of Louisiana (District Court). Cajun's complaint seeks to annul, rescind, terminate, and/or dissolve the Joint Ownership Participation and Operating Agreement entered into on August 28, 1979 (Operating Agreement) relating to River Bend. Cajun alleges fraud and error by GSU, breach of its fiduciary duties owed to Cajun, and/or GSU's repudiation, renunciation, abandonment, or dissolution of its core obligations under the Operating Agreement, as well as the lack or failure of cause and/or consideration for Cajun's performance under the Operating Agreement. The suit also seeks to recover Cajun's alleged $1.6 billion investment in the unit as damages, plus attorneys' fees, interest, and costs. Two member cooperatives of Cajun have brought an independent action to declare the Operating Agreement void, based upon failure to get prior LPSC approval alleged to be necessary. GSU believes the suits are without merit and is contesting them vigorously.

A trial without jury on the portion of the suit by Cajun to rescind the Operating Agreement which began in April 1994 has been completed, and an order from the District Court is pending. No assurance can be given as to the outcome of this litigation. If GSU were ultimately unsuccessful in this litigation and were required to make substantial payments, GSU would probably be unable to make such payments and would probably have to seek relief from its creditors under the United States Bankruptcy Code. If GSU prevails in this litigation, there can be no assurance that the Bankruptcy Court will allow funding of all required costs of Cajun's ownership in River Bend.

Since 1992 Cajun has not paid its full share of operating and maintenance expenses and other costs for repairs and improvements to River Bend. In addition, certain costs and expenses paid by Cajun were paid under protest. These actions were taken by Cajun based on its contention, which GSU disagrees, that River Bend's operating and maintenance expenses were excessive.

In a letter dated October 21, 1994, and at a subsequent meeting, Cajun representatives advised Entergy Corporation and GSU that, on October 25, 1994, Cajun would exhaust its 1994 budget for operating and maintenance expenses for River Bend, and did not make any further payments to GSU in 1994 for River Bend operating, maintenance, or capital costs. Cajun also advised that the RUS (which provided funding to Cajun for its investment in River Bend) would not permit Cajun to budget funds in 1995 to pay its share of operating and maintenance expenses or capital costs for River Bend. However, Cajun stated that it would continue to fund its

share of the nuclear decommissioning trust payments for River Bend, as well as insurance and safety-related expenses. The unpaid portion of Cajun's River Bend operating, maintenance, and capital costs for 1994 (which has been fully reserved) was approximately $22.4 million. Cajun's total share of River Bend annual operating (including nuclear fuel) and maintenance expenses and capital costs was approximately $76.1 million in 1994.

In view of Cajun's stated expectation that it will fund only a limited portion of its share of River Bend related operating, maintenance, and capital costs, GSU notified Cajun that it would (i) credit GSU's share of expenses for Big Cajun 2, Unit 3 against amounts due from Cajun to GSU and (ii) seek to market Cajun's share of the power from River Bend and apply the proceeds to the amounts due from Cajun to GSU. On November 2, 1994, Cajun discontinued GSU's entitlement of energy from Big Cajun 2, Unit 3. In response, on November 3, 1994, GSU filed pleadings in District Court seeking an order requiring Cajun to provide GSU with the energy from Big Cajun 2, Unit 3 to which GSU is entitled, and holding that GSU is entitled to credit amounts due from GSU to Cajun for Big Cajun 2, Unit 3 against amounts due from Cajun to GSU with respect to River Bend. On December 19, 1994, the District Court issued an injunction prohibiting Cajun from denying its share of energy from Big Cajun 2, Unit 3 and stipulating that GSU must make payments for its portion of expenses for Big Cajun 2, Unit 3 to the registry of the District Court.

On December 14, 1994, the LPSC ordered Cajun to decrease the rates charged to its member distribution cooperatives by approximately $30 million per year. The rate decrease is associated with the LPSC's prior finding of imprudence in Cajun's participation in River Bend.

On December 21, 1994, Cajun filed a petition in the United States Bankruptcy Court for the Middle District of Louisiana seeking bankruptcy relief under Chapter 11 of the United States Bankruptcy Code. Cajun's bankruptcy could have a material adverse effect on GSU, including the possibility of an NRC action with respect to the operation of River Bend. However, GSU is taking appropriate steps to protect its interests and its claims against Cajun arising from the co-ownership in River Bend and Big Cajun 2, Unit 3. On December 31, 1994, the District Court issued an order lifting an automatic stay as to certain proceedings, with the result that the preliminary injunction granted by the Court on December 19, 1994, remains in effect. Cajun filed a Notice of Appeal on January 18, 1995, to the United States Court of Appeals for the Fifth Circuit seeking a reversal of the District Court's grant of the preliminary injunction. No hearing date has been set on Cajun's appeal.

In the bankruptcy proceedings, Cajun filed on January 10, 1995, a motion to reject the River Bend Operating Agreement as a burdensome executory contract. GSU responded on January 10, 1995, with a memorandum opposing Cajun's motion filed with the District Court. This memorandum argues that the motion should be denied because (1) the Operating Agreement is not an executory contract that can be rejected under the United States Bankruptcy Code, but an agreement establishing property rights and obligations; (2) Cajun legally cannot have its payment obligations under the Operating Agreement suspended while retaining the benefits from co-ownership in River Bend, as the benefits and obligations are indivisible; (3) Cajun cannot seek to dispose of its property interest in River Bend or reject the Operating Agreement with respect thereto without disposing of all of its property interests and rejecting all of the arrangements under the River Bend package of agreements consisting of the Operating Agreement, Big Cajun 2, Unit 3 facility, certain transmission lines and the buy-back agreement pursuant to when GSU paid Cajun approximately $600 million for River Bend capacity and energy during the early years of operation of River Bend; and (4) a legal determination of Cajun's obligations and interests in River Bend should only be made as part of a plan of reorganization in bankruptcy and such determination should be subject to regulatory approvals by certain agencies with jurisdiction over Cajun, including the NRC. If the court were to grant Cajun's motion to reject the Operating Agreement, Cajun would be relieved of its financial obligations under the contract, while GSU would likely have a substantial damage claim arising from any such rejection. Although

GSU believes that Cajun's motion to reject the Operating Agreement is non-meritorious, it is not possible to predict the outcome or ultimate impact of these proceedings.

During the period in which Cajun is not paying its share of River Bend costs, GSU intends to fund all costs necessary for the safe, continuing operation of the unit. The responsibilities of Entergy Operations as the licensed operator of River Bend, for safely operating and maintaining the unit are not affected by Cajun's actions.

The total resulting from Cajun's failure to fund repair projects, Cajun's funding limitation on refueling outages, and the weekly funding limitation by Cajun was $55.6 million as of December 31, 1994, compared with $33.3 million as of December 31, 1993. These amounts are reflected in long-term receivables with an offsetting reserve in other deferred credits. Cajun's bankruptcy may affect the ultimate collectibility of the amounts owed to GSU, including any amounts that may be awarded in litigation.

In September 1994, in connection with Entergy Corporation's analysis of certain preacquisition contingencies, Entergy Corporation increased its acquisition adjustment and GSU recorded a loss provision associated with the River Bend litigation between GSU and Cajun and certain underpayments by Cajun of River Bend costs, in accordance with SFAS 5, "Accounting for Contingencies." See Note 12 for additional information on provisions for preacquisition contingencies recorded during 1994.

Cajun - Transmission Service

GSU and Cajun are parties to FERC proceedings relating to transmission service charge disputes. In April 1992, FERC issued a final order. In May 1992, GSU and Cajun filed motions for rehearings which are pending at FERC. In June 1992, GSU filed a petition for review in the United States Court of Appeals regarding certain of the issues decided by FERC. In August 1993, the United States Court of Appeals rendered an opinion reversing the FERC order regarding the portion of such disputes relating to the calculations of certain credits and equalization charges under GSU's service schedules with Cajun. The opinion remanded the issues to FERC for further proceedings consistent with its opinion. In December 1994, FERC held a hearing to address the issues remanded by the Court of Appeals. In February 1995, FERC clarified its order, eliminating an issue that GSU believes the Court of Appeals directed FERC to reconsider.

GSU interprets the 1992 FERC order and the United States Court of Appeals' decision to mean that Cajun would owe GSU approximately $93.3 million as of December 31, 1994. However, FERC's February 1995, order indicates that FERC believes an issue, estimated by GSU to constitute approximately $26.2 million of this amount, may not be pursued by GSU in the remand proceedings. GSU further estimates that if it prevails in its May 1992 motion for rehearing, Cajun would owe GSU approximately $129.6 million as of December 31, 1994. If Cajun were to prevail in its May 1992 motion for rehearing to FERC, and if GSU were not to prevail in its May 1992 motion for rehearing to FERC, and if FERC does not implement the court's remand as GSU contends is required, GSU estimates it would owe Cajun approximately $85.6 million as of December 31, 1994. The above amounts are exclusive of a $7.3 million payment by Cajun on December 31, 1990, which the parties agreed to apply to the disputed transmission service charges. GSU and Cajun further agreed that their positions at FERC would remain unaffected by the $7.3 million payment. Pending FERC's ruling on the May 1992 motions for rehearing, GSU has continued to bill Cajun utilizing the historical billing methodology and has booked underpaid transmission charges, including interest, in the amount of $160.2 million as of December 31, 1994. This amount is reflected in long-term receivables with an offsetting reserve in other deferred credits.

Capital Requirements and Financing

Construction expenditures (excluding nuclear fuel) for the years 1995, 1996, and 1997 are estimated to total $568 million, $568 million, and $565 million, respectively. The System will also require $1.4 billion during the period 1995-1997 to meet long-term debt and preferred stock maturities and cash sinking fund requirements. The System plans to meet the above requirements primarily with internally generated funds and cash on hand, supplemented by the issuance of debt and preferred stock. Certain System companies may also continue with the acquisition or refinancing of all or a portion of certain outstanding series of preferred stock and long-term debt.

Capital Funds and Availability Agreements

Entergy Corporation has agreed to supply to System Energy sufficient capital to (1) maintain System Energy's equity capital at an amount equal to a minimum of 35% of its total capitalization (excluding short-term debt), and (2) permit the continuation of commercial operation of Grand Gulf 1 and to pay in full all indebtedness for borrowed money of System Energy when due under any circumstances. In addition, under supplements to the Capital Funds Agreement assigning System Energy's rights as security for specific debt of System Energy, Entergy Corporation has agreed to make cash capital contributions to enable System Energy to make payments on such debt when due.

System Energy has entered into various agreements with AP&L, LP&L, MP&L, and NOPSI, whereby AP&L, LP&L, MP&L, and NOPSI are obligated to purchase their respective entitlements of capacity and energy from System Energy's 90% ownership and leasehold interest in Grand Gulf 1, and to make payments that, together with other available funds, are adequate to cover System Energy's operating expenses. System Energy would have to secure funds from other sources, including Entergy Corporation's obligations under the Capital Funds Agreement, to cover any shortfalls from payments received from AP&L, LP&L, MP&L, and NOPSI under these agreements.

Long-Term Contracts

The System has several long-term contracts to purchase natural gas and low-sulfur coal for use at its generating units. LP&L has a long-term agreement through the year 2031 to purchase energy generated by a hydroelectric facility. If the maximum percentage (94%) of the energy is made available to LP&L, current production projections would require estimated payments of approximately $47 million per year through 1996, $54 million in 1997, and a total of $3.5 billion for the years 1998 through 2031. LP&L recovers the cost of purchased energy through its fuel adjustment clause.

In 1988, GSU entered into a joint venture with a primary term of 20 years with Conoco, Inc., Citgo Petroleum Corporation, and Vista Chemical Company (Industrial Participants) whereby GSU's Nelson Units 1 and 2 were sold to a partnership (NISCO) consisting of the Industrial Participants and GSU. The Industrial Participants are supplying the fuel for the units, while GSU operates the units at the discretion of the Industrial Participants and purchases the electricity produced by the units. GSU is continuing to sell electricity to the Industrial Participants. For the years ended December 31, 1994, 1993, and 1992, the purchases of electricity from the joint venture totaled $58.3 million, $62.6 million, and $37.8 million, respectively.

Nuclear Insurance

The Price-Anderson Act limits public liability for a single nuclear incident to approximately $8.92 billion as of December 31, 1994. The System has protection for this liability through a combination of private insurance (currently $200 million each) and an industry assessment program. Under the assessment program, the maximum amount the System would be required to pay for each nuclear incident would be $79.3 million per reactor, payable at a rate of $10 million per licensed reactor per incident per year. As a co-licensee of Grand Gulf 1 with System Energy, South Mississippi Electric Power Association (SMEPA) would share 10% of this obligation. With respect to River Bend, any assessments pertaining to this program are allocated in accordance with the respective ownership interests of GSU and Cajun. The System has five licensed reactors. In addition, the System participates in a private insurance program which provides coverage for worker tort claims filed for bodily injury caused by radiation exposure. The program provides for a maximum assessment of approximately $16 million for the System's five nuclear units in the event losses exceed accumulated reserve funds.

AP&L, GSU, LP&L, and System Energy are also members of certain insurance programs that provide coverage for property damage, including decontamination and premature decommissioning expense, to members' nuclear generating plants. As of December 31, 1994, AP&L, GSU, LP&L, and System Energy each were insured against such losses up to $2.75 billion, with $250 million of this amount designated to cover any shortfall in the NRC required decommissioning trust funding. In addition, AP&L, GSU, LP&L, MP&L, and NOPSI are members of an insurance program that covers certain replacement power and business interruption costs incurred due to prolonged nuclear unit outages. Under the property damage and replacement power/business interruption insurance programs, these System companies could be subject to assessments if losses exceed the accumulated funds available to the insurers. As of December 31, 1994, the maximum amounts of such possible assessments were: AP&L - $37.2 million; GSU - $22.6 million; LP&L - $34.7 million; MP&L - $0.9 million; NOPSI - $0.5 million; and System Energy - $29.7 million. Under its agreement with System Energy, SMEPA would share in System Energy's obligation. Cajun shares approximately $4.4 million of GSU's obligation.

The amount of property insurance presently carried by the System exceeds the NRC's minimum requirement for nuclear power plant licensees of $1.06 billion per site. NRC regulations provide that the proceeds of this insurance must be used, first, to place and maintain the reactor in a safe and stable condition and, second, to complete decontamination operations. Only after proceeds are dedicated for such use and regulatory approval is secured, would any remaining proceeds be made available for the benefit of plant owners or their creditors.

Spent Nuclear Fuel and Decommissioning Costs

AP&L, GSU, LP&L, and System Energy provide for estimated future disposal costs for spent nuclear fuel in accordance with the Nuclear Waste Policy Act of 1982. The affected System companies entered into contracts with the Department of Energy (DOE), whereby the DOE will furnish disposal service at a cost of one mill per net KWH generated and sold after April 7, 1983, plus a one-time fee for generation prior to that date. AP&L, the only System company that generated electricity with nuclear fuel prior to that date, elected to pay the one-time fee, plus accrued interest, no earlier than 1998, and has recorded a liability as of December 31, 1994, of approximately $105 million. The fees payable to the DOE may be adjusted in the future to assure full recovery. The System considers all costs incurred or to be incurred, except accrued interest, for the disposal of spent nuclear fuel to be proper components of nuclear fuel expense, and provisions to recover such costs have been or will be made in applications to regulatory authorities.

Delays have occurred in the DOE's program for the acceptance and disposal of spent nuclear fuel at a permanent repository. In a statement released February 17, 1993, the DOE asserted that it does not have a legal

obligation to accept spent nuclear fuel without an operational repository for which it has not yet arranged. Currently the DOE projects it will begin to accept spent fuel no earlier than 2010. In the meantime, all System companies are responsible for spent fuel storage. Current on-site spent fuel storage capacity at River Bend, Waterford 3, and Grand Gulf 1 is estimated to be sufficient until 2003, 2000, and 2004, respectively. Thereafter, the affected companies will provide additional storage. Current on-site spent fuel storage capacity at ANO is estimated to be sufficient until mid-1995, at which time an ANO storage facility using dry casks will begin operation. This facility is estimated to provide sufficient storage until 2000, with the capability of being expanded further as required. The initial cost of providing the additional on-site spent fuel storage capability required at ANO, River Bend, Waterford 3, and Grand Gulf 1 is expected to be approximately $5 million to $10 million per unit. In addition, approximately $3 million to $5 million per unit will be required every two to three years subsequent to 1995 for ANO and every four to five years subsequent to 2003, 2000, and 2004 for River Bend, Waterford 3, and Grand Gulf 1, respectively, until the DOE's repository begins accepting such units' spent fuel.

Entergy Operations and System Fuels joined in lawsuits against the DOE, seeking clarification of the DOE's responsibility to receive spent nuclear fuel beginning in 1998. The original suits, filed June 20, 1994, asked for a ruling stating that the Nuclear Waste Policy Act require the DOE to begin taking title to the spent fuel and to start removing it from nuclear power plants in 1998, a mandate for the DOE's nuclear waste management program to begin accepting fuel in 1998 and court monitoring of the program, and the potential for escrow of payments to a nuclear waste fund instead of directly to the DOE.

Decommissioning costs for ANO, River Bend (excluding Cajun's 30% share), Waterford 3, and Grand Gulf 1 (excluding Southern Mississippi Electric Power Association's 10% share) were estimated to be approximately $806.3 million (based on a 1994 interim update to the 1992 cost study), $267.8 million (based on a 1991 cost study reflecting 1990 dollars), $320.1 million (based on a 1994 updated study in 1993 dollars), and $365.9 million (based on a 1994 cost study using 1993 dollars), respectively. AP&L is authorized to recover through rates amounts that, when added to estimated investment income, should be sufficient to meet the above estimated decommissioning costs for ANO. GSU is currently recovering in rates decommissioning costs based on the 1985 original cost study of $141 million. GSU filed a 1991 study with the PUCT requesting a rate adjustment for decommissioning expense. As discussed in Note 2, on March 20, 1995, the PUCT ruled in the current rate case. The PUCT order included recovery of River Bend decommissioning costs totaling $204.9 million. GSU plans to include the 1991 study in its next LPSC rate review scheduled for mid-1995. LP&L currently is recovering in rates decommissioning costs based on a 1988 study update reflecting a cost of $203 million. LP&L filed with the LPSC a request for a rate adjustment for decommissioning expense based on a 1994 cost study update and the matter is under review. System Energy is currently recovering in rates amounts sufficient to fund $198 million (in 1989 dollars) of its decommissioning costs. A filing with FERC to request the updated decommissioning costs in rates is under consideration by System Energy. AP&L, GSU, LP&L, and System Energy regularly review and update estimated decommissioning costs, and applications will be made to the appropriate regulatory authorities to reflect in rates any future change in projected decommissioning costs. The amounts recovered in rates are deposited in external trust funds and reported at market value. The accumulated decommissioning liability has been recorded in accumulated depreciation for AP&L, GSU, and LP&L, and in other deferred credits for System Energy, in the amounts of $137.4 million, $22.2 million, $28.2 million, and $31.9 million, respectively, as of December 31, 1994. Decommissioning expense amounting to $25.1 million was recorded in 1994. The actual decommissioning costs may vary from the estimates because of regulatory requirements, changes in technology, and increased costs of labor, materials, and equipment. Management believes that actual decommissioning costs are likely to be higher than the amounts presented above.

The staff of the SEC has questioned certain of the current accounting practices of the electric utility industry, regarding the recognition, measurement, and classification of decommissioning costs for nuclear

generating stations in the financial statements of electric utilities. In response to these questions, the FASB is currently reviewing the accounting for decommissioning. If current electric utility industry accounting practices for such decommissioning are changed, annual provisions for decommissioning could increase, the estimated cost for decommissioning could be recorded as a liability rather than as accumulated depreciation, and trust fund income from the external decommissioning trusts could be reported as investment income rather than as a reduction to decommissioning expense.

The EPAct has a provision that assesses domestic nuclear utilities with fees for the decontamination and decommissioning of the DOE's past uranium enrichment operations. The decontamination and decommissioning assessments will be used to set up a fund into which contributions from utilities and the federal government will be placed. AP&L's, GSU's, LP&L's, and System Energy's annual assessments, which will be adjusted annually for inflation, are approximately $3.4 million, $0.9 million, $1.3 million, and $1.4 million (in 1995 dollars), respectively, for approximately 15 years. FERC requires that utilities treat these assessments as costs of fuel as they are amortized. The cumulative liability of $75.9 million as of December 31, 1994, is recorded in other current liabilities and other noncurrent liabilities and is offset in the consolidated financial statements by a regulatory asset.

ANO Matters

ANO 2 experienced a forced outage for repair of certain steam generator tubes in March 1992. Further inspections and repairs were conducted at subsequent refueling and mid-cycle outages in September 1992, May 1993, April 1994, and January 1995. AP&L's budgeted maintenance expenditures were adequate to cover the cost of such repairs. ANO 2's output has been reduced 15 megawatts or 1.6% due to secondary side fouling, tube plugging, and reduction of primary temperature. Entergy Operations continues to take steps at ANO 2 to reduce the number and severity of future tube cracks. In addition, Entergy Operations continues to meet with the NRC to discuss such steps and results of inspections of the steam generator tubes, as well as the timing of future inspections. Additional inspections are planned for the normal refueling outage scheduled for October 1995.

Sales/Use Tax Issues

In September 1994, the Louisiana Supreme Court (Court) issued an opinion (in a case in which none of the System companies was a party) holding, in part, that the Louisiana state legislature's suspension of state sales and use tax exemptions also had the effect of suspending exemptions from local sales and use taxes. On January 27, 1995 the Court, after rehearing, reversed its opinion. Because of the Court's most recent ruling, sales of electricity and gas, fuels and other items used by GSU, LP&L, and NOPSI to generate electricity in Louisiana, as well as other items exempt from sales and use taxes, continue to be exempt from local sales and use taxes, even though the state exemptions for sales and use tax have been suspended.

NOTE 9. LEASES

General

As of December 31, 1994, the System had capital leases and noncancelable operating leases (excluding nuclear fuel leases and the sale and leaseback transactions discussed below) with minimum lease payments as follows:

Year	Capital Leases	Operating Leases
	(In Thousands)	
1995	$ 33,008	$ 65,429
1996	29,054	57,133
1997	24,653	48,861
1998	24,634	47,446
1999	24,610	43,128
Years thereafter	136,294	246,303
Minimum lease payments	272,253	$508,300
Less: Amount representing interest	103,596	
Present value of net minimum lease payments	$168,657	

Rental expense for capital and operating leases (excluding nuclear fuel leases and the sale and leaseback transactions) amounted to approximately $64.8 million, $62.7 million, and $75.5 million in 1994, 1993, and 1992, respectively.

Nuclear Fuel Leases

AP&L, GSU, LP&L, and System Energy have arrangements to lease nuclear fuel in an aggregate amount up to $430 million as of December 31, 1994. The lessors finance their acquisitions of nuclear fuel through credit agreements and the issuance of notes. If a lessor cannot arrange financing upon maturity of its borrowings, the lessee must purchase nuclear fuel in an amount sufficient to enable the lessor to retire such borrowings.

Lease payments are based on nuclear fuel use. Nuclear fuel lease expense for AP&L, GSU, LP&L, and System Energy of $163.4 million (including interest of $27.3 million) was charged to operations in 1994. Excluding GSU, nuclear fuel expense of $145.8 million and $158.4 million (including interest of $20.5 million and $25.6 million) was charged to operations in 1993 and 1992, respectively.

Sale and Leaseback Transactions

In 1988 and 1989, System Energy and LP&L, respectively, sold and leased back portions of their ownership interests in Grand Gulf 1 and Waterford 3, for 26 1/2-year and 28-year lease terms, respectively. Both companies have options to terminate the leases, to repurchase the sold interests, or to renew the leases at the end of their terms.

Under System Energy's sale and leaseback arrangements, letters of credit are required to be maintained to secure certain amounts payable, for the benefit of equity investors, by System Energy under the leases. The letters of credit currently maintained are effective until January 1997. It is expected that the letters of credit will either be

renewed, extended, or replaced prior to expiration. On January 18, 1994, System Energy refinanced the debt portion of the sale and leaseback arrangements. The new secured lease obligation bonds of $356 million, 7.43% series due 2011, and $79 million, 8.2% series due 2014, will be indirectly secured by liens on, and a security interest in, certain ownership interests and the respective leases relating to Grand Gulf 1.

LP&L did not exercise its option to repurchase the undivided interests in Waterford 3 on the fifth anniversary (September 1994) of the closing date of the sale and leaseback transactions. As a result, LP&L was required to provide collateral to the Owner Participants for the equity portion of certain amounts payable by LP&L under the lease. Such collateral was in the form of a new series of non-interest bearing first mortgage bonds in the aggregate principal amount of $208.2 million issued by LP&L in September 1994 under its first mortgage bond indenture.

As of December 31, 1994, System Energy and LP&L had future minimum lease payments (reflecting implicit rates of 7.02% after the above refinancing and 8.76%, respectively) as follows:

	System Energy	LP&L
	(In Thousands)	
1995	$ 42,464	$ 32,569
1996	42,753	35,165
1997	42,753	39,805
1998	42,753	41,447
1999	42,753	50,530
Years thereafter	802,820	676,214
Total	$1,016,296	$ 875,730

NOTE 10. POSTRETIREMENT BENEFITS

Pension Plans

The System companies have various postretirement benefit plans covering substantially all of their employees. The pension plans are noncontributory and provide pension benefits that are based on employees' credited service and compensation during the final years before retirement. Entergy Corporation and its subsidiaries fund pension costs in accordance with contribution guidelines established by the Employee Retirement Income Security Act of 1974, as amended, and the Internal Revenue Code of 1986, as amended. The assets of the plans include common and preferred stocks, fixed income securities, interest in a money market fund, and insurance contracts.

Total 1994, 1993, and 1992 pension cost of Entergy Corporation and its subsidiaries (excluding GSU for 1993 and 1992), including amounts capitalized, included the following components:

	For the Years Ended December 31,		
	1994	1993	1992
		(In Thousands)	
Service cost - benefits earned during the period	$ 35,712	$21,760	$18,784
Interest cost on projected benefit obligation	77,943	53,371	50,225
Actual return on plan assets	10,381	(81,708)	(43,772)
Net amortization and deferral	(96,893)	27,261	(8,243)
Other	17,963	-	-
Net pension cost	$ 45,106	$20,684	$16,994

The funded status of Entergy's various pension plans as of December 31, 1994 and 1993 was:

	1994	1993
	(In Thousands)	
Actuarial present value of accumulated pension plan obligation:		
Vested	$ 851,194	$ 851,726
Nonvested	6,479	17,867
Accumulated benefit obligation	$ 857,673	$ 869,593
Plan assets at fair value	$1,014,430	$1,059,715
Projected benefit obligation	999,153	1,064,364
Plan assets in excess of (less than) projected benefit obligation	15,277	(4,649)
Unrecognized prior service cost	25,501	20,288
Unrecognized transition asset	(54,209)	(61,561)
Unrecognized net loss (gain)	(9,332)	32,634
Accrued pension liability	$ (22,763)	$ (13,288)

The pension liability for 1993 has been restated in order to make GSU's presentation of certain Early Retirement Plan liabilities consistent with the other System companies. The significant actuarial assumptions used in computing the information above for 1994, 1993, and 1992 (only 1994 and 1993 with respect to GSU's plan), were as follows: weighted average discount rate, 8.5% for 1994, 7.5% for 1993, and 8.25% for 1992; weighted average rate of increase in future compensation levels, 5.1% for 1994 and 5.6% (5% for GSU) for 1993 and 1992; and expected long-term rate of return on plan assets, 8.5%. Transition assets of the System are being amortized over the greater of the remaining service period of active participants or 15 years.

Other Postretirement Benefits

The System companies also provide certain health care and life insurance benefits for retired employees. Substantially all employees may become eligible for these benefits if they reach retirement age while still working for the System companies. The cost of providing these benefits, recorded on a cash basis, to retirees in 1992 (excluding GSU) was approximately $13 million.

Effective January 1, 1993, Entergy adopted SFAS 106. The new standard requires a change from a cash method to an accrual method of accounting for postretirement benefits other than pensions. The System operating companies, other than MP&L and NOPSI, continue to fund these benefits on a pay-as-you-go basis. During 1994, pursuant to regulatory directives, MP&L and NOSPI began to fund their postretirement benefit obligation. At January 1, 1993, the actuarially determined accumulated postretirement benefit obligation (APBO) earned by retirees and active employees was estimated to be approximately $241.4 million and $128 million for Entergy (other than GSU) and for GSU, respectively. Such obligations are being amortized over a 20-year period beginning in 1993.

The System operating companies have sought approval, in their respective regulatory jurisdictions, to implement the appropriate accounting requirements related to SFAS 106 for ratemaking purposes. AP&L has received an order permitting deferral, as a regulatory asset, of these costs. MP&L is expensing its SFAS 106 costs, which are reflected in rates pursuant to an order from the MPSC in connection with MP&L's formulary incentive rate plan (see Note 2). The LPSC ordered GSU and LP&L to use the pay-as-you-go method for ratemaking purposes for postretirement benefits other than pensions, but the LPSC retains the flexibility to examine individual companies' accounting for postretirement benefits to determine if special exceptions to this order are warranted. NOPSI is expensing its SFAS 106 costs. Pursuant to resolutions adopted in November 1993 by the Council related to the Merger, NOPSI's SFAS 106 expenses through October 31, 1996, will be allowed by the Council for purposes of evaluating the appropriateness of NOPSI's rates. Pursuant to a ruling by the PUCT applicable to all Texas utilities, including GSU, amounts recorded in compliance with SFAS 106 and included in a rate filing test period, will be recoverable in rates (at the time of the next general rate case), and postretirement benefits amounts allowed in rates must then be funded by the utility.

Total 1994 and 1993 postretirement benefit cost of Entergy Corporation and its subsidiaries (excluding GSU for 1993), including amounts capitalized and deferred, included the following components:

	1994	1993
	(In Thousands)	
Service cost - benefits earned during the period	$ 11,863	$ 7,751
Interest cost on APBO	23,312	19,394
Return on plan assets	-	(71)
Net amortization and deferral	9,891	12,071
Net periodic postretirement benefit cost	$ 45,066	$ 39,145

The funded status of Entergy's postretirement plans as of December 31, 1994 and 1993, was:

	1994	1993
	(In Thousands)	
Accumulated postretirement benefit obligation:		
Retirees	$ 186,570	$ 221,562
Other fully eligible participants	58,330	68,283
Other active participants	52,324	95,854
	297,224	385,699
Plan assets at fair value	9,733	354
Plan assets less than APBO	(287,491)	(385,345)
Unrecognized transition obligation	217,275	229,346
Unrecognized net loss (gain)	(58,178)	28,529
Accrued postretirement benefit liability	$(128,394)	$(127,470)

The assumed health care cost trend rate used in measuring the APBO of the System companies was 9.4% for 1995, gradually decreasing each successive year until it reaches 5.0% in 2011. A one percentage-point increase in the assumed health care cost trend rate for each year would have increased the APBO of the System companies, as of December 31, 1994, by 8.9%, and the sum of the service cost and interest cost by approximately 11.3%. The assumed discount rate and rate of increase in future compensation used in determining the APBO were 8.5% for 1994 and 7.5% for 1993 and 5.1% for 1994 and 5.5% (5% for GSU) for 1993, respectively.

NOTE 11. RESTRUCTURING COSTS

During the third quarter of 1994, Entergy announced a restructuring program related to certain of its operating units. The program is designed to reduce costs, improve operating efficiencies, and increase shareholder value in order to enable Entergy to become a low-cost producer. The program includes reductions in the number of employees and the consolidation of offices and facilities. In 1994, AP&L, GSU, LP&L, MP&L, and NOPSI recorded restructuring charges of $12.5 million, $6.5 million, $6.8 million, $6.2 million, and $3.4 million, respectively. These charges primarily include employee severance costs related to the expected termination of approximately 1,850 employees. As of December 31, 1994, 35 AP&L employees were terminated under the program at a severance cost of approximately $0.3 million.

NOTE 12. ENTERGY CORPORATION-GSU MERGER

On December 31, 1993, Entergy Corporation and GSU consummated their Merger. GSU became a wholly-owned subsidiary of Entergy Corporation and continues to operate as a corporation under the regulation of FERC, the PUCT, and the LPSC. As consideration to GSU's shareholders, Entergy Corporation paid $250 million and issued 56,695,724 shares of its common stock in exchange for the 114,055,065 outstanding shares of GSU common stock. In addition, $33.5 million of transaction costs were capitalized in connection with the Merger.

As a result of the December 31, 1993, Merger closing, GSU recorded expenses totaling $49 million, net of related tax effects, for early retirement and other severance related plans and the payment to financial consultants involved in Merger negotiations on behalf of GSU. Additionally, GSU recorded $23.8 million in 1994 for remaining severance and augmented retirement benefits related to the Merger. See Note 2 for information regarding Merger-related rate agreements.

In 1993, Entergy Corporation recorded an acquisition adjustment in utility plant in the amount of $380 million representing the excess of the purchase price over the net assets acquired of GSU. The acquisition adjustment will be amortized on a straight-line basis over a 31-year period, which approximates the remaining average book life of GSU's plant. During the allocation period (which expired on December 31, 1994), Entergy Corporation completed its analyses with respect to preacquisition contingencies and revised the allocation of the purchase price for a number of preacquisition contingencies. In 1994, GSU wrote off assets or recorded liabilities totaling approximately $137 million net of tax for the Cajun-River Bend litigation, unfunded Cajun-River Bend costs, environmental cleanup costs, obsolete spare parts, Louisiana River Bend rate deferrals previously disallowed by the LPSC, plant held for future use, and a PUCT fuel reconciliation settlement. Any items recorded in 1995 or later will result in write-offs and/or losses charged to operations on GSU's financial statements and Entergy Corporation's consolidated financial statements.

In accordance with the purchase method of accounting, the 12-month results of operations for Entergy Corporation reported in its Statements of Consolidated Income, Cash Flows, and Retained Earnings do not reflect GSU's results of operations for any period prior to January 1, 1994, as a result of the Merger. The pro forma combined revenues, net income, earnings per common share before extraordinary items, cumulative effect of accounting changes, and earnings per common share of Entergy Corporation presented below give effect to the Merger as if it had occurred at January 1, 1992. This unaudited pro forma information is not necessarily indicative of the results of operations that would have occurred had the Merger been consummated for the period for which it is being given effect, nor is it necessarily indicative of future operating results.

	Year Ended December 31,	
	1993	1992
	(In Thousands, Except Per Share Amounts)	
Revenues	$6,286,999	$5,850,973
Net income	$ 595,211	$ 521,783
Earnings per average common share before extraordinary items and cumulative effect of accounting changes	$ 2.10	$ 2.26
Earnings per average common share	$ 2.57	$ 2.24

NOTE 13. QUARTERLY FINANCIAL DATA (UNAUDITED)

The business of the System is subject to seasonal fluctuations with the peak period occurring during the third quarter. Consolidated operating results for the four quarters of 1994 and 1993 were:

	Operating Revenue	Operating Income	Net Income (Loss)	Earnings (Loss) per Share
	(In Thousands, Except Per Share Amounts)			
1994:				
First Quarter	$1,406,039	$253,870	$ 70,735	$ 0.31
Second Quarter	$1,586,298	$325,935	$ 144,337	$ 0.63
Third Quarter	$1,805,524	$336,611	$ 143,198	$ 0.63
Fourth Quarter	$1,165,429	$152,325	$ (16,429)	$(0.07)
1993:				
First Quarter	$ 926,412	$192,743	$ 151,154	$ 0.86
Second Quarter	$1,070,102	$260,574	$ 130,860	$ 0.75
Third Quarter	$1,410,951	$359,938	$ 233,430	$ 1.34
Fourth Quarter	$1,077,872	$180,086	$ 36,486	$ 0.21

See Note 1 for information regarding the recording of the cumulative effect of the change in accounting principle for unbilled revenues in January 1993.

ENTERGY CORPORATION AND SUBSIDIARIES
SELECTED FINANCIAL DATA - FIVE-YEAR COMPARISON

	1994	1993	1992	1991	1990
	(In Thousands, Except Per Share Amounts)				
Operating revenues	$ 5,963,290	$ 4,485,337	$ 4,116,499	$ 4,051,429	$ 3,982,062
Income before cumulative effect of a change in accounting principle	$ 341,841	$ 458,089	$ 437,637	$ 482,032	$ 478,318
Earnings per share before cumulative effect of a change in accounting principle	$ 1.49	$ 2.62	$ 2.48	$ 2.64	$ 2.44
Dividends declared per share	$ 1.80	$ 1.65	$ 1.45	$ 1.25	$ 1.05
Return on average common equity	5.31%	12.58%	10.31%	11.57%	11.47%
Book value per share, year-end (2)	$ 27.93	$ 28.27	$ 24.35	$ 23.46	$ 22.18
Total assets (2)	$ 22,613,491	$ 22,876,697	$ 14,239,537	$ 14,383,102	$ 14,831,394
Long-term obligations (1)(2)	$ 7,817,366	$ 8,177,882	$ 5,630,505	$ 5,801,364	$ 6,395,951

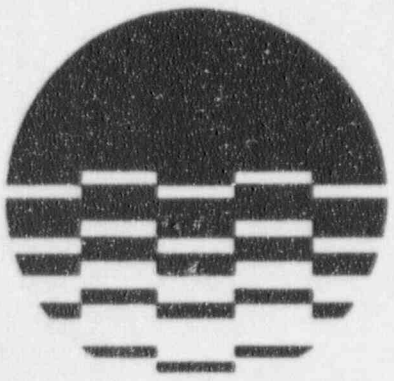
(1) Includes long-term debt (excluding currently maturing debt), preferred and preference stock with sinking fund, and noncurrent capital lease obligations.

(2) 1993 amounts include the effects of the Merger in accordance with the purchase method of accounting for combinations (see Note 11).

	1994	1993	1992	1991	1990
	(Dollars in Thousands)				
Electric Operating Revenues:					
Residential	$ 2,126,260	$1,596,480	$1,440,360	$1,463,281	$1,449,768
Commercial	1,499,206	1,072,583	1,007,420	996,619	988,409
Industrial	1,832,916	1,199,172	1,097,023	1,068,802	1,051,796
Governmental	159,694	136,649	127,753	128,762	124,597
Total retail	5,618,076	4,004,884	3,672,556	3,657,464	3,614,570
Sales for resale	311,018	293,894	252,288	220,347	212,504
Other (1)	(131,325)	95,568	118,711	96,667	67,045
Total	$ 5,797,769	$4,394,346	$4,043,555	$3,974,478	$3,894,119
Billed Electric Energy Sales (Millions of KWH):					
Residential	26,231	18,946	17,549	18,329	18,174
Commercial	20,050	13,420	12,928	13,164	12,977
Industrial	41,030	24,889	23,610	23,466	22,795
Governmental	2,233	1,887	1,839	1,903	1,831
Total retail	89,544	59,142	55,926	56,862	55,777
Sales for resale	7,908	8,291	7,979	7,346	6,292
Total	97,452	67,433	63,905	64,208	62,069

(1) 1994 includes the effects of the FERC Settlement, the 1994 NOPSI Settlement, and a GSU reserve for rate refund.

Arkansas Power & Light Company/1994 Financial Statements



AP&L

ARKANSAS POWER & LIGHT COMPANY

DEFINITIONS

Certain abbreviations or acronyms used in AP&L's Financial Statements, Notes to Financial Statements, and Management's Financial Discussion and Analysis are defined below:

Abbreviation or Acronym	Term
AFUDC	Allowance for Funds Used During Construction
ANO	Arkansas Nuclear One Steam Electric Generating Station
ANO 2	Unit No. 2 of ANO
AP&L	Arkansas Power & Light Company
APSC	Arkansas Public Service Commission
DOE	United States Department of Energy
Entergy or System	Entergy Corporation and its various direct and indirect subsidiaries
Entergy Operations	Entergy Operations, Inc., a subsidiary of Entergy Corporation that has operating responsibility for Grand Gulf 1, Waterford 3, ANO, and River Bend
Entergy Services	Entergy Services, Inc.
Entergy Power	Entergy Power, Inc., a subsidiary of Entergy Corporation that markets capacity and energy for resale from certain generating facilities to other parties, principally non-affiliates
EPAct	The Energy Policy Act of 1992
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
Grand Gulf Station	Grand Gulf Steam Electric Generating Station (nuclear)
Grand Gulf 1	Unit No. 1 of the Grand Gulf Station (nuclear)
Grand Gulf 2	Unit No. 2 of the Grand Gulf Station (nuclear)
GSU	Gulf States Utilities Company (including wholly-owned subsidiaries - Varibus Corporation, GSG&T, Inc., Prudential Oil and Gas, Inc., and Southern Gulf Railway Company)
Independence Station	Independence Steam Electric Generating Station

Abbreviation or Acronym	Term
KWH	Kilowatt-Hour(s)
LP&L	Louisiana Power & Light Company
Merger	The combination transaction, consummated on December 31, 1993, by which GSU became a subsidiary of Entergy Corporation and Entergy Corporation became a Delaware Corporation
Money Pool	Entergy Money Pool, which allows certain System companies to borrow from, or lend to, certain other System companies
MP&L	Mississippi Power & Light Company
NOPSI	New Orleans Public Service Inc.
NRC	Nuclear Regulatory Commission
OBRA	Omnibus Budget Reconciliation Act of 1993
Revised Settlement Agreement	Arkansas Settlement Agreement, as modified by the APSC order issued October 6, 1988, to bring the Grand Gulf 1-related phase-in plan into compliance with the requirements of SFAS 92, "Regulated Enterprises - Accounting for Phase-in Plans"
SEC	Securities and Exchange Commission
SFAS	Statement of Financial Accounting Standards promulgated by the FASB
SFAS 106	SFAS 106, "Employers' Accounting for Postretirement Benefits Other Than Pensions"
SFAS 109	SFAS 109, "Accounting for Income Taxes"
System or Entergy	Entergy Corporation and its various direct and indirect subsidiaries
System Energy	System Energy Resources, Inc.
System Fuels	System Fuels, Inc.
System operating companies	AP&L, GSU, LP&L, MP&L, and NOPSI, collectively
Union Electric	Union Electric Company of St. Louis, Missouri
White Bluff Station	White Bluff Steam Electric Generating Station

ARKANSAS POWER & LIGHT COMPANY

REPORT OF MANAGEMENT

The management of Arkansas Power & Light Company has prepared and is responsible for the financial statements and related financial information included herein. The financial statements are based on generally accepted accounting principles. Financial information included elsewhere in this report is consistent with the financial statements.

To meet its responsibilities with respect to financial information, management maintains and enforces a system of internal accounting controls that is designed to provide reasonable assurance, on a cost-effective basis, as to the integrity, objectivity, and reliability of the financial records, and as to the protection of assets. This system includes communication through written policies and procedures, an employee Code of Conduct, and an organizational structure that provides for appropriate division of responsibility and the training of personnel. This system is also tested by a comprehensive internal audit program.

The independent public accountants provide an objective assessment of the degree to which management meets its responsibility for fairness of financial reporting. They regularly evaluate the system of internal accounting controls and perform such tests and other procedures as they deem necessary to reach and express an opinion on the fairness of the financial statements.

Management believes that these policies and procedures provide reasonable assurance that its operations are carried out with a high standard of business conduct.

EDWIN LUPBERGER
Chairman and Chief Executive Officer

GERALD D. MCINVALE
Senior Vice President and
Chief Financial Officer

ARKANSAS POWER & LIGHT COMPANY

AUDIT COMMITTEE CHAIRMAN'S LETTER

The Entergy Corporation Board of Directors' Audit Committee functions as the Audit Committee for Arkansas Power & Light Company. The Audit Committee is comprised of four directors, who are not officers of AP&L: H. Duke Shackelford (Chairman), Lucie J. Fjeldstad, Dr. Norman C. Francis, and James R. Nichols. The committee held four meetings during 1994.

The Audit Committee oversees AP&L's financial reporting process on behalf of the Board of Directors and provides reasonable assurance to the Board that sufficient operating, accounting, and financial controls are in existence and are adequately reviewed by programs of internal and external audits.

The Audit Committee discussed with Entergy's internal auditors and the independent public accountants (Coopers & Lybrand L.L.P.) the overall scope and specific plans for their respective audits, as well as AP&L's financial statements and the adequacy of AP&L's internal controls. The committee met, together and separately, with Entergy's internal auditors and independent public accountants, without management present, to discuss the results of their audits, their evaluation of AP&L's internal controls, and the overall quality of AP&L's financial reporting. The meetings also were designed to facilitate and encourage any private communication between the committee and the internal auditors or independent public accountants.

H. DUKE SHACKELFORD
Chairman, Audit Committee

REPORT OF INDEPENDENT ACCOUNTANTS

To the Board of Directors and Shareholders of
Arkansas Power & Light Company

We have audited the accompanying balance sheet of Arkansas Power & Light Company as of December 31, 1994, and the related statements of income, retained earnings and cash flows for the year then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audit. The financial statements of the Company as of December 31, 1993 and for the years ended December 31, 1993 and 1992, were audited by other auditors, whose report, dated February 11, 1994, included an explanatory paragraph that described changes in methods of accounting for revenues, income taxes and postretirement benefits other than pensions which are discussed in Notes 1, 3 and 10 respectively, to these financial statements.

We conducted our audit in accordance with generally accepted auditing standards. Those standards require that we plan and perform the audit to obtain reasonable assurance 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 audit provides a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 1994, and the result of its operations and its cash flows for the year then ended in conformity with generally accepted accounting principles.

COOPERS & LYBRAND L.L.P.
New Orleans, Louisiana
February 21, 1995

INDEPENDENT AUDITORS' REPORT

To the Shareholders and the Board of Directors of
Arkansas Power & Light Company

We have audited the accompanying balance sheet of Arkansas Power & Light Company (AP&L) as of December 31, 1993, and the related statements of income, retained earnings, and cash flows for each of the two years in the period ended December 31, 1993. These financial statements are the responsibility of AP&L's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with generally accepted auditing standards. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such financial statements present fairly, in all material respects, the financial position of AP&L at December 31, 1993, and the results of its operations and its cash flows for each of the two years in the period ended December 31, 1993 in conformity with generally accepted accounting principles.

As discussed in Note 1 to the financial statements, AP&L changed its method of accounting for revenues in 1993 and, as discussed in Notes 3 and 10 to the financial statements, in 1993 AP&L changed its methods of accounting for income taxes and postretirement benefits other than pensions, respectively.

DELOITTE & TOUCHE LLP
New Orleans, Louisiana
February 11, 1994

ARKANSAS POWER & LIGHT COMPANY
BALANCE SHEETS
ASSETS

	December 31,	
	1994	1993
	(In Thousands)	
Utility Plant:		
Electric	$4,293,097	$4,098,355
Property under capital leases	56,135	62,139
Construction work in progress	136,701	197,005
Nuclear fuel under capital lease	94,628	93,606
Total	4,580,561	4,451,105
Less - accumulated depreciation and amortization	1,710,216	1,604,318
Utility plant - net	2,870,345	2,846,787
Other Property and Investments:		
Investment in subsidiary companies - at equity	11,215	11,232
Decommissioning trust fund	127,136	108,192
Other - at cost (less accumulated depreciation)	4,628	4,257
Total	142,979	123,681
Current Assets:		
Cash and cash equivalents:		
Cash	3,737	1,825
Temporary cash investments - at cost, which approximates market:		
Associated companies	4,713	-
Other	72,306	-
Total cash and cash equivalents	80,756	1,825
Accounts receivable:		
Customer (less allowance for doubtful accounts of $2.0 million in 1994 and $2.1 million in 1993)	53,781	65,641
Associated companies	28,506	18,312
Other	11,181	20,817
Accrued unbilled revenues	83,863	83,378
Fuel inventory - at average cost	34,561	51,920
Materials and supplies - at average cost	79,886	81,398
Rate deferrals	113,630	92,592
Deferred excess capacity	8,414	9,115
Prepayments and other	23,867	28,303
Total	518,445	453,301
Deferred Debits and Other Assets:		
Regulatory Assets:		
Rate deferrals	360,496	475,387
Deferred excess capacity	20,060	28,465
SFAS 109 regulatory asset - net	227,068	234,015
Unamortized loss on reacquired debt	57,344	60,169
Other regulatory assets	68,813	72,360
Other	26,665	39,940
Total	760,446	910,336
TOTAL	$4,292,215	$4,334,105

See Notes to Financial Statements.

ARKANSAS POWER & LIGHT COMPANY
BALANCE SHEETS
CAPITALIZATION AND LIABILITIES

	December 31,	
	1994	1993
	(In Thousands)	
Capitalization:		
Common stock, $0.01 par value, authorized 325,000,000 shares; issued and outstanding 46,980,196 shares in 1994 and 1993	$470	$470
Paid-in capital	590,844	590,844
Retained earnings	491,799	448,811
Total common shareholder's equity	1,083,113	1,040,125
Preferred stock:		
Without sinking fund	176,350	176,350
With sinking fund	58,527	70,027
Long-term debt	1,293,879	1,313,315
Total	2,611,869	2,599,817
Other Noncurrent Liabilities:		
Obligations under capital leases	94,534	94,861
Other	68,235	66,575
Total	162,769	161,436
Current Liabilities:		
Currently maturing long-term debt	28,175	3,020
Notes payable:		
Associated companies	-	21,395
Other	34,667	667
Accounts payable:		
Associated companies	17,345	45,177
Other	89,329	93,611
Customer deposits	17,113	15,241
Taxes accrued	45,239	43,013
Accumulated deferred income taxes	25,043	32,367
Interest accrued	31,064	31,410
Dividends declared	4,727	5,049
Co-owner advances	20,639	39,435
Deferred fuel cost	20,254	16,130
Nuclear refueling reserve	37,954	30,677
Obligations under capital leases	56,154	60,883
Other	45,632	26,034
Total	473,335	464,109
Deferred Credits:		
Accumulated deferred income taxes	859,558	876,618
Accumulated deferred investment tax credits	118,548	154,723
Other	66,136	77,402
Total	1,044,242	1,108,743
Commitments and Contingencies (Notes 2, 8, and 9)		
TOTAL	$4,292,215	$4,334,105

See Notes to Financial Statements.

ARKANSAS POWER & LIGHT COMPANY
STATEMENTS OF CASH FLOWS

	For the Years Ended December 31,		
	1994	1993	1992
		(In Thousands)	
Operating Activities:			
Net income	$142,263	$205,297	$130,529
Noncash items included in net income:			
Cumulative effect of a change in accounting principle	-	(50,187)	-
Change in rate deferrals/excess capacity-net	102,959	84,712	60,344
Depreciation and decommissioning	149,878	135,530	132,459
Deferred income taxes and investment tax credits	(54,080)	(6,965)	(820)
Allowance for equity funds used during construction	(4,001)	(3,627)	(4,173)
Gain on sale of property - net	-	-	(19,612)
Changes in working capital:			
Receivables	10,817	7,385	(22,281)
Fuel inventory	17,359	173	17,039
Accounts payable	(32,114)	20,608	(5,393)
Taxes accrued	2,226	(21,983)	(23,492)
Interest accrued	(346)	201	(8,041)
Other working capital accounts	20,324	26,486	5,249
Decommissioning trust contributions	(11,581)	(11,491)	(13,255)
Provision for estimated losses and reserves	16,617	1,963	(21,670)
Other	(4,744)	(41,826)	(2,736)
Net cash flow provided by operating activities	355,577	346,276	224,147
Investing Activities:			
Construction expenditures	(179,116)	(176,540)	(179,320)
Proceeds from sale of property	-	-	67,985
Allowance for equity funds used during construction	4,001	3,627	4,173
Nuclear fuel purchases	(40,074)	(29,156)	(34,238)
Proceeds from sale/leaseback of nuclear fuel	40,074	29,156	34,238
Net cash flow used in investing activities	(175,115)	(172,913)	(107,162)
Financing Activities:			
Proceeds from issuance of:			
First mortgage bonds	-	445,000	148,114
Preferred stock	-	-	14,222
Other long-term debt	27,992	48,070	3,973
Retirement of:			
First mortgage bonds	(800)	(441,141)	(329,019)
Other long-term debt	(30,231)	(47,700)	(1,225)
Redemption of preferred stock	(11,500)	(15,500)	(34,388)
Changes in short-term borrowings	12,605	17,395	4,000
Dividends paid:			
Common stock	(80,000)	(156,300)	(75,000)
Preferred stock	(19,597)	(21,362)	(23,730)
Net cash flow used in financing activities	(101,531)	(171,538)	(293,053)
Net increase (decrease) cash and cash equivalents	78,931	1,825	(176,068)
Cash and cash equivalents at beginning of period	1,825	-	176,068
Cash and cash equivalents at end of period	$80,756	$1,825	-
SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION:			
Cash paid during the period for:			
Interest - net of amount capitalized	$98,787	$103,826	$114,791
Income taxes	$79,553	$66,366	$60,987
Noncash investing and financing activities:			
Capital lease obligations incurred	$47,719	$48,513	$37,351
Excess of fair value of decommissioning trust assets over amount invested	$1,361	-	-

See Notes to Financial Statements.

LIQUIDITY AND CAPITAL RESOURCES

Liquidity is important to AP&L due to the capital intensive nature of its business, which requires large investments in long-lived assets. While large capital expenditures for the construction of new generating capacity are not currently planned, AP&L does require significant capital resources for the periodic maturity of certain series of debt and preferred stock and ongoing construction. Net cash flow from operations totaled $356 million, $346 million, and $224 million in 1994, 1993, and 1992, respectively. Net cash flow from operations increased in 1993 due primarily to increased electric sales and increased collections under the phase-in plan, as discussed below. In recent years, this cash flow, supplemented by issuances of debt, has been sufficient to meet substantially all investing and financing requirements, including capital expenditures, dividends, and debt/preferred stock maturities. AP&L's ability to fund these capital requirements results, in part, from its continued efforts to streamline operations and reduce costs, as well as collections under its Grand Gulf 1 rate phase-in plan which exceed the current cash requirements for Grand Gulf 1-related costs. (In the income statement, these revenue collections are offset by the amortization of previously deferred costs; therefore, there is no effect on net income.) AP&L's Grand Gulf 1 phase-in plan will continue to contribute to AP&L's cash position through 1998. See Note 2 for additional information on AP&L's rate phase-in plan. See Note 8 for additional information on AP&L's capital and refinancing requirements in 1995 - 1997. Also, to the extent current market interest and dividend rates allow, AP&L may continue to refinance high-cost debt and preferred stock prior to maturity.

Earnings coverage tests and bondable property additions limit the amount of first mortgage bonds and preferred stock that AP&L can issue. Based on the most restrictive applicable tests as of December 31, 1994, and an assumed annual interest or dividend rate of 9.25%, AP&L could have issued $253 million of additional first mortgage bonds or $468 million of additional preferred stock. AP&L has the conditional ability to issue first mortgage bonds and preferred stock against the retirement of first mortgage bonds and preferred stock, respectively, in some cases, without satisfying an earnings coverage test.

See Notes 5 and 6 for information on AP&L's financing activities and Note 4, for information on AP&L's short-term borrowings and lines of credit.

ARKANSAS POWER & LIGHT COMPANY
STATEMENTS OF INCOME

	For the Years Ended December 31,		
	1994	1993	1992
		(In Thousands)	
Operating Revenues	$1,590,742	$1,591,568	$1,521,129
Operating Expenses:			
Operation and maintenance:			
Fuel and fuel-related expenses	261,932	257,983	242,040
Purchased power	328,379	349,718	417,099
Nuclear refueling outage expenses	33,107	30,069	40,512
Other operation and maintenance	390,472	373,758	363,768
Depreciation and decommissioning	149,878	135,530	132,459
Taxes other than income taxes	33,610	28,626	26,709
Income taxes	9,938	18,746	4,058
Amortization of rate deferrals	166,793	160,916	114,711
Total	1,374,109	1,355,346	1,341,356
Operating Income	216,633	236,222	179,773
Other Income (Deductions):			
Allowance for equity funds used during construction	4,001	3,627	4,173
Miscellaneous - net	48,049	64,884	113,842
Income taxes	(19,282)	(32,451)	(46,531)
Total	32,768	36,060	71,484
Interest Charges:			
Interest on long-term debt	106,001	110,472	121,676
Other interest - net	4,811	9,118	2,308
Allowance for borrowed funds used during construction	(3,674)	(2,418)	(3,256)
Total	107,138	117,172	120,728
Income before Cumulative Effect of a Change in Accounting Principle	142,263	155,110	130,529
Cumulative Effect to January 1, 1993 of Accruing Unbilled Revenues (net of income taxes of $31,140)	-	50,187	-
Net Income	142,263	205,297	130,529
Preferred Stock Dividend Requirements and Other	19,275	20,877	23,202
Earnings Applicable to Common Stock	$122,988	$184,420	$107,327

See Notes to Financial Statements

ARKANSAS POWER & LIGHT COMPANY
STATEMENTS OF RETAINED EARNINGS

	For the Years Ended December 31,		
	1994	1993	1992
		(In Thousands)	
Retained Earnings, January 1	$448,811	$420,691	$388,364
Add:			
Net income	142,263	205,297	130,529
Total	591,074	625,988	518,893
Deduct:			
Dividends declared:			
Preferred stock	19,275	20,877	23,202
Common stock	80,000	156,300	75,000
Total	99,275	177,177	98,202
Retained Earnings, December 31 (Note 7)	$491,799	$448,811	$420,691

See Notes to Financial Statements.

Net Income

Net income decreased in 1994 due primarily to the one-time recording in the first quarter of 1993 of the cumulative effect of the change in accounting principle for unbilled revenues and its ongoing effects, and to increased operation and maintenance expenses as a result of restructuring costs and storm damage activity during 1994.

Net income increased in 1993 due primarily to the one-time recording of the cumulative effect of the change in accounting principle for unbilled revenues (see Note 1), and its ongoing effects, partially offset by the effect of the implementation of SFAS 109 (see Note 3) and by the impact in March 1992 of an after-tax gain from the sale of AP&L's retail properties in Missouri. Effective January 1, 1993, AP&L began accruing as revenues the charges for energy delivered to customers but not yet billed. Electric revenues were previously recorded on a cycle-billing basis. Excluding the above mentioned items, net income for 1993 would have been $157.7 million and net income for 1992 would have been $110.9 million. This increase of $46.8 million is due primarily to increased retail energy sales.

Significant factors affecting the results of operations and causing variances between the years 1994 and 1993, and 1993 and 1992, are discussed under "Revenues and Sales," "Expenses," and "Other" below.

Revenues and Sales

See "Selected Financial Data - Five-Year Comparison," following the notes, for information on operating revenues by source and KWH sales.

Total revenues remained relatively unchanged in 1994. Retail revenue decreased primarily due to lower fuel recovery revenue during the year offset by increased sales for resale to associated companies in 1994, caused by changes in generation availability and requirements among the System operating companies.

Electric operating revenues were higher in 1993 due to an increase in residential and commercial energy sales resulting from a return to more normal weather as compared to milder weather in 1992. Industrial sales increased primarily in the lumber/plywood and petroleum/natural gas pipeline industries. Additionally, electric revenues increased as a result of increased collections of previously deferred Grand Gulf 1-related costs, which do not impact net income.

Expenses

Operating expenses increased in 1994 due primarily to increased other operation and maintenance expenses and increased amortization of rate deferrals partially offset by lower purchased power expenses. Operating expenses increased in 1993 due primarily to higher fuel expense, income tax expense and increased amortization of rate deferrals.

Other operation and maintenance expenses increased in 1994 primarily due to the storm damage costs and restructuring costs as discussed in Note 12. The decrease in 1994 purchased power expenses is primarily due to the decrease in the price of purchased power.

Fuel for electric generation and fuel-related expenses increased in 1993 due primarily to an increase in generation requirements resulting primarily from increased retail energy sales and increased fuel costs as discussed in "Revenues and Sales" above. Purchased power decreased in 1993 due primarily to energy demands being met by increased nuclear generation.

Total income taxes decreased during 1994 primarily due to the write-off of unamortized deferred investment tax credit of $27.3 million due to a FERC settlement and due to lower pretax income in 1994. This decrease was partially offset by an increase in tax expense due to the true-up of actual income tax expense for 1993 determined during 1994.

Total income taxes increased in 1993 due primarily to higher pretax income, an increase in the federal income tax rate as a result of OBRA, and the effect of implementing SFAS 109.

The amortization of rate deferrals increased in 1993 due to increased amortization of previously deferred Grand Gulf 1-related costs pursuant to the step-up provisions of AP&L's phase-in plan.

Other

Miscellaneous other income - net decreased in 1994 due primarily to reduced Grand Gulf 1 carrying charges. Miscellaneous other income - net decreased in 1993 due primarily to the impact of the pretax gain on the 1992 sale of AP&L's retail properties in Missouri.

Other income taxes decreased in 1994 primarily due to a lower pretax income as discussed above.

Interest on long-term debt decreased in 1994 and 1993 due primarily to the continued refinancing of high-cost debt.

Competition

The electric utility industry is becoming increasingly competitive and AP&L is seeking to become a leading competitor in the changing electric energy business. Competition presents AP&L with many challenges. The following have been identified by AP&L as its major competitive challenges.

Retail and Wholesale Rate Issues

Increasing competition in the utility industry brings an increased need to stabilize or reduce retail rates. In connection with the Merger, AP&L agreed with its retail regulator not to request any general retail rate increases that would take effect before November 1998, with certain exceptions. See Note 2 for further information. Recognizing that many industrial customers have energy alternatives, AP&L continues to work with these customers to address their needs. In certain cases, competitive prices are negotiated, using variable rate designs.

Retail wheeling, the transmission by an electric utility of energy produced by another entity over the utility's transmission and distribution system to a retail customer in the electric utility's service territory, is evolving. Over a dozen states have been studying the concept of retail competition. In April 1994, the state of Michigan agreed to a five-year experiment that allows limited competition among public utilities. During the same month, the California Public Utilities Commission proposed to deregulate that state's electric power industry, starting on January 1, 1996, to allow the largest industrial customers to select the lowest cost supplier for electricity service. Under the proposal, by the year 2002, smaller companies and residential customers in California would also be able to buy power from any suppliers. The California Public Utilities Commission is currently reviewing its decision and is expected to make a ruling in the first half of 1995. The retail market for electricity is expected to become more competitive with such moves toward deregulation.

In some areas of the country, municipalities (or comparable entities) whose residents are served at retail by an investor-owned utility pursuant to a franchise are exploring the possibility of establishing new or extending existing distribution systems or seeking new delivery points in order to serve retail customers, especially large industrial customers, that currently receive service from an investor-owned utility. These options depend on the terms of a utility's franchise as well as on state law and regulation. In addition, FERC's authority to order utilities to transmit for a new or expanding municipal system is limited in certain respects. Where successful, however, the establishment of a municipal system or the acquisition by a municipal system of a utility's customers could result in the inability to recover costs that the utility has incurred in serving those customers.

In mid-1994, the FERC issued a notice of proposed rulemaking concerning a regulatory framework for dealing with recovery of stranded costs, such as high cost nuclear generating units, which may be incurred by electric utilities as a result of increased competition. In addition to addressing recovery of stranded costs related to wholesale service, the proposal requested comment as to recovery of retail stranded costs in transmission rates where state regulatory authorities failed to address the issue or were in conflict. Comments and reply comments have been filed, and the matter is pending. The risk of exposure to stranded costs which may result from competition in the industry will depend on the extent and timing of retail competition, the resolution of jurisdictional issues concerning stranded cost recovery, and the extent to which such costs are recovered from departing or remaining customers, among other matters.

In the wholesale rate area, FERC approved in 1992, with certain modifications, the proposal of AP&L, LP&L, MP&L, NOPSI, and Entergy Power to sell wholesale power at market-based rates and to provide to electric utilities "open access" to the System's transmission system (subject to certain requirements). GSU was later added to this filing. On October 31, 1994, as amended on January 25, 1995, Entergy Services filed with FERC revised transmission tariffs intended to provide access to transmission service on the same or comparable basis, terms, and conditions as the System operating companies, and the matter is pending. Open access and market pricing, once in effect, will increase marketing opportunities for AP&L, but will also expose AP&L to the risk of loss of load or reduced revenues due to competition with alternative suppliers.

In March 1994, North Little Rock, Arkansas, awarded AP&L a wholesale power contract that will provide estimated revenues of $347 million over 11 years. Under the contract, the price per KWH was reduced 18%, with increases in price through the year 2004. AP&L, which has been serving North Little Rock for over 40 years, was awarded the contract after intense bidding with several competitors. On May 22, 1994, FERC accepted the contract. Rehearings were requested by one of AP&L's competitors and were held in February 1995. The matter is pending.

In light of the rate issues discussed above, AP&L is aggressively reducing costs to avoid potential earnings erosions that might result as well as to become more competitive. In 1994, AP&L announced a restructuring program related to certain of its operating units. This program is designed to reduce costs and improve operating efficiencies. See Note 12 for further information. Also, in response to an increasingly competitive environment, AP&L announced intentions to revise its initial least cost planning activities.

The Energy Policy Act of 1992

The EPAct addresses a wide range of energy issues and is altering the way Entergy and the rest of the electric utility industry operate. The EPAct encourages competition and affords utilities the opportunities, and the risks, associated with an open and more competitive market environment. The EPAct creates exemptions from regulation under the Holding Company Act and creates a class of exempt wholesale generators consisting of utility affiliates and nonutilities that are owners and operators of facilities for the generation and transmission of power for sales at wholesale. The EPAct also gives FERC the authority to order investor-owned utilities, including AP&L, to transmit power and energy to or for wholesale purchasers and sellers. The law creates the potential for electric utilities and other power producers to gain increased access to the transmission systems of other entities to facilitate wholesale sales. Both AP&L and Entergy Power expect to compete in this market.

Litigation and Regulatory Proceedings

In November 1994, FERC approved an agreement settling a long-standing dispute involving income tax allocation procedures of System Energy. In accordance with the agreement, System Energy refunded approximately $22.2 million to AP&L, which will in turn make refunds or credits to its customers (except for those portions attributable to its retained share of Grand Gulf 1 costs). Additionally, System Energy will refund a total of approximately $22.3 million, plus interest, to AP&L over the period through June 2004. The settlement also required the write-off of approximately $27.3 million of certain related unamortized balances of deferred investment tax credits by AP&L.

ANO Matters

ANO 2 experienced a forced outage for repair of certain steam generator tubes in March 1992. Further inspections and repairs were conducted at subsequent refueling and mid-cycle outages in September 1992, May 1993, April 1994, and January 1995. AP&L's budgeted maintenance expenditures were adequate to cover the cost of such repairs. ANO 2's output has been reduced 15 megawatts or 1.6% due to secondary side fouling, tube plugging, and reduction of primary temperature. Entergy Operations continues to take steps at ANO 2 to reduce the number and severity of future tube cracks. In addition, Entergy Operations continues to meet with the NRC to discuss such steps and results of inspections of the generator tubes, as well as the timing of future inspections. Additional inspections are planned for the normal refueling outage scheduled for October 1995.

Accounting Issues

Proposed Accounting Standards - The FASB has proposed a SFAS on "Accounting for the Impairment of Long-Lived Assets," effective January 1, 1996. The proposed standard describes circumstances which may result in assets being impaired and provides criteria for recognition and measurement of asset impairment. Certain operations of AP&L are potentially affected by this standard, and any resulting write-offs will depend on future operating costs, generating units' efficiency and availability, and the future market for energy over the remaining life of the units. Based on current estimates, AP&L anticipates that future revenues will fully recover the costs of such operations.

Continued Application of SFAS 71 - AP&L's financial statements currently reflect assets and costs based on current cost-based ratemaking regulations, in accordance with SFAS 71, "Accounting for the Effects of Certain Types of Regulation." As discussed above, the electric utility industry is changing and these changes could possibly result in the discontinuance of the application of SFAS 71, which would result in the elimination of regulatory assets and liabilities. See Note 1 for further information.

Accounting for Decommissioning Costs - The FASB is currently reviewing the accounting for decommissioning of nuclear plants. This project could possibly change AP&L's, as well as the entire utility industry's, accounting for such costs. For further information, see Note 8.

NOTE 1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

AP&L maintains accounts in accordance with FERC and other regulatory guidelines. Certain previously reported amounts have been reclassified to conform to current classifications.

Revenues and Fuel Costs

Prior to January 1, 1993, AP&L recorded revenues when billed to its customers with no accrual for energy delivered but not yet billed. To provide a better matching of revenues and expenses, effective January 1, 1993, AP&L adopted a change in accounting principle to provide for accrual of estimated unbilled revenues. The cumulative effect of this accounting change as of January 1, 1993 increased net income by $50.2 million. Had this new accounting method been in effect during prior years, net income before the cumulative effect would not have been materially different from that shown in the accompanying financial statements.

Substantially all of AP&L's rate schedules include fuel adjustment clauses that allow either current recovery or deferrals of fuel costs until such costs are reflected in the related revenues. The fuel adjustment clause provides, as an incentive with respect to ANO, for over- or under-recovery of the cost of replacement energy in excess of the cost of equal amounts of nuclear energy when the units are not down for refueling.

Utility Plant

Utility plant is stated at original cost. The original cost of utility plant retired or removed, plus the applicable removal costs, less salvage, is charged to accumulated depreciation. Maintenance, repairs, and minor replacement costs are charged to operating expenses. Substantially all of AP&L's utility plant is subject to the lien of its mortgage and deed of trust.

Total AP&L net utility plant in service of $2.64 billion as of December 31, 1994 includes $1.23 billion of production plant, $.43 billion of transmission plant, $.82 billion of distribution plant, and $.16 billion of other plant.

Depreciation is computed on the straight-line basis at rates based on the estimated service lives and costs of removal of the various classes of property. Depreciation provisions on average depreciable property approximated 3.4% in 1994, 1993 and 1992.

AFUDC represents the approximate net composite interest cost of borrowed funds and a reasonable return on the equity funds used for construction. Although AFUDC increases utility plant and increases earnings, it is only realized in cash through depreciation provisions included in rates. AP&L's effective composite rates for AFUDC were 9.2%, 10.3%, and 10.5% for 1994, 1993, and 1992, respectively.

Jointly-Owned Generating Stations

AP&L is a co-owner of two coal-fueled, two-unit generating stations, the White Bluff Station and the Independence Station. AP&L is the agent for the respective co-owners and operates the stations. AP&L records the investment and expenses associated with these generating stations to the extent of its ownership interests. As of December 31, 1994, AP&L's investment and accumulated depreciation in these generating stations were as follows:

Generating Stations		Total Megawatt Capability	Ownership	Investment	Accumulated Depreciation
				(In Thousands)	
White Bluff:	Units 1 and 2	1,660	57.00%	$400,918	$ 151,830
Independence:	Unit 1	836	31.50%	$116,555	$ 38,594
	Common Facilities		15.75%	$ 29,331	$ 8,758

Income Taxes

AP&L, its parent, and affiliates file a consolidated federal income tax return. Income taxes are allocated to AP&L in proportion to its contribution to consolidated taxable income. SEC regulations require that no Entergy Corporation subsidiary pay more taxes than it would have had a separate income tax return been filed. Deferred taxes are recorded for all temporary differences between book and taxable income. Investment tax credits are deferred and amortized based upon the average useful life of the related property in accordance with rate treatment. As discussed in Note 3, in 1993 AP&L changed its accounting for income taxes to conform with SFAS 109.

Reacquired Debt

The premiums and costs associated with reacquired debt are being amortized over the life of the related new issuances, in accordance with ratemaking treatment.

Cash and Cash Equivalents

AP&L considers all unrestricted highly liquid debt instruments purchased with an original maturity of three months or less to be cash equivalents.

Continued Application of SFAS 71

As a result of the EPAct and actions of regulatory commissions, the electric utility industry is moving toward a combination of competition and a modified regulatory environment. AP&L's financial statements currently reflect assets and costs based on current cost-based ratemaking regulations, in accordance with SFAS 71, "Accounting for the Effects of Certain Types of Regulation." Continued applicability of SFAS 71 to AP&L's financial statements requires that rates set by an independent regulator on a cost of service basis (including a reasonable rate of return on invested capital) can actually be charged to and collected from customers.

In the event that either all or a portion of a utility's operations cease to meet those criteria for various reasons, including deregulation, a change in the method of regulation or a change in the competitive environment for the utility's regulated services, the utility should discontinue application of SFAS 71 for the relevant portion. That discontinuation should be reported by elimination from the balance sheet of the effects of any actions of regulators recorded as regulatory assets and liabilities.

As of December 31, 1994, and for the foreseeable future, AP&L's financial statements continue to follow SFAS 71.

Fair Value Disclosure

The estimated fair value of financial instruments has been determined by AP&L, using available market information and appropriate valuation methodologies. However, considerable judgment is required in developing the estimates of fair value. Therefore, estimates are not necessarily indicative of the amounts that AP&L could realize in a current market exchange. In addition, gains or losses realized on financial instruments may be reflected in future rates and not accrue to the benefit of stockholders.

AP&L considers the carrying amounts of financial instruments classified as current assets and liabilities to be a reasonable estimate of their fair value because of the short maturity of these instruments. In addition, AP&L does not presently expect that performance of its obligations will be required in connection with certain off-balance sheet commitments and guarantees considered financial instruments. Due to this factor, and because of the related party nature of these commitments and guarantees, determination of fair value is not considered practicable. See Notes 5, 6, and 8 for additional fair value disclosure.

AP&L adopted the provisions of SFAS 115, "Accounting for Certain Investments in Debt and Equity Securities," effective January 1, 1994. As a result, at December 31, 1994, AP&L recorded on the balance sheet an additional $1.4 million in decommissioning trust funds, representing the amount by which the fair value of the securities held in such funds exceeds the amounts for decommissioning recovered in rates and deposited in the funds and the related earnings on the amounts deposited. Due to the regulatory treatment for decommissioning trust funds, AP&L recorded an offsetting amount in unrealized gains on investment securities as a regulatory liability.

NOTE 2. RATE AND REGULATORY MATTERS

Merger - Related Rate Agreement

In November 1993, AP&L and the APSC entered into a settlement agreement whereby the APSC agreed to withdraw its request for hearing and its objections in the SEC proceeding related to the Merger. In return AP&L agreed, among other things, (a) that it will not request any general retail rate increase that would take effect before November 3, 1998, except for, among other things, increases associated with the recovery of certain Grand Gulf 1-related costs, excess capacity costs, and costs related to the adoption of SFAS 106 that were previously deferred, recovery of certain taxes, and force majeure (defined to include, among other things, war, natural catastrophes, and high inflation); and (b) that its retail ratepayers would be protected from (1) increases in its cost of capital resulting from risks associated with the Merger, (2) recovery of any portion of the acquisition premium or transactional costs associated with the Merger, (3) certain direct allocations of costs associated with GSU's River Bend nuclear unit, and (4) any losses of GSU resulting from resolution of litigation in connection with its ownership of River Bend.

Arkansas - Revised Settlement Agreement

Pursuant to the terms of the Revised Settlement Agreement, AP&L (1) permanently retains 7.92% (stated as a percentage of System Energy's share of Grand Gulf 1) of its Grand Gulf 1-related costs (Retained Share) for 1994 and all succeeding years of commercial operation of the unit; (2) recovers currently 28.08% of such costs in 1994 and thereafter; and (3) deferred a portion of such costs for future recovery (Deferred Balance). AP&L is permitted to currently recover carrying charges on the unrecovered portion of the Deferred Balance. For the year ended December 31, 1994, $170 million was billed to AP&L by System Energy.

AP&L has the right under the Revised Settlement Agreement to sell capacity and energy available from its Retained Share to third parties, which shall not include AP&L's wholesale customers. In the event AP&L is not able to sell such capacity and energy to such third parties, it has the right to sell the energy available from such capacity, and to date a significant portion has been sold, to its retail customers at a price equal to AP&L's avoided energy cost, which is currently less than AP&L's cost of such energy. The Revised Settlement Agreement requires that a portion of the proceeds from sales of Retained Share capacity and energy to third parties prior to January 1, 1996 be applied to reduce the Deferred Balance.

Arkansas - Rate Riders

In conjunction with the Revised Settlement Agreement, AP&L was permitted to implement annual updates to the Grand Gulf 1 rate rider, increasing Arkansas retail rates by approximately 3.1% and 2.6% for the years 1992 and 1991, respectively. These increases reflect scheduled phase-in plan increases adjusted for any prior year over- or under-collection. Beginning in 1993 and continuing for a five-year period, rates will remain at the 1992 level, unless adjustments are made for an over-or under-collection of Grand Gulf 1-related costs in excess of $10 million. Although it was not required under the terms of the Grand Gulf 1 rate rider, in 1993 AP&L opted to implement a 0.7% rate refund in 1994 for a cumulative over-recovery amount of $7.3 million.

Various other rate riders, which modify non-Grand Gulf 1 rates under the Revised Settlement Agreement, have been implemented with respect to tax adjustments, depreciation, decommissioning costs, and deferred return on excess capacity (which is being recovered over a 10-year period ending in 1998).

Missouri Retail Operations

In March 1992, AP&L sold its retail properties in Missouri to Union Electric for approximately $68 million. The gain on the sale, classified as "Other Income-Miscellaneous" in the 1992 Statement of Income, was approximately $33.7 million, which resulted in a $19.6 million increase in net income after taxes. In addition, AP&L agreed to sell to Union Electric 120 megawatts of capacity and associated energy for an initial period of 10 years, and beginning on January 1, 1995, Union Electric shall also purchase 40 megawatts of peaking capacity from AP&L.

February 1994 Ice Storm

In early February 1994, an ice storm left more than 97,000 AP&L customers without electric power across the service area. The storm was the most severe natural disaster ever to affect the System, causing damage to transmission and distribution lines, equipment, poles, and facilities in certain areas. Repair costs totaled approximately $30.8 million with $18.7 million of these amounts capitalized as plant-related costs. The remaining balance has been charged against regulatory storm damage reserves.

NOTE 3. INCOME TAXES

Income tax expense consisted of the following:

	For the Years Ended December 31,		
	1994	1993	1992
		(In Thousands)	
Current:			
Federal	$64,238	$47,326	$45,932
State	19,062	10,836	11,156
Total	83,300	58,162	57,088
Deferred - net:			
Liberalized depreciation	9,314	7,074	4,929
Alternative minimum tax	30,601	(2,227)	6,577
Nuclear refueling and maintenance	(2,855)	(2,161)	7,751
Deferred purchased power costs	(42,529)	(35,896)	(14,375)
Deferred excess capacity costs	(3,487)	(4,044)	(3,190)
Unbilled revenue	1,330	26,847	(2,474)
Bond reacquisition costs	(1,108)	14,706	5,184
TCBY Tower (CADC)	44	8,743	-
Decontamination and decommissioning fund	676	16,429	-
Nuclear reserve	(1,537)	(37)	1,747
Other	(8,388)	5,314	(2,659)
Total	(17,939)	34,748	3,490
Investment tax credit adjustments - net	(8,814)	(10,573)	(9,989)
Investment tax credit amortization - FERC settlement	(27,327)	-	-
Recorded income tax expense	$29,220	$82,337	$50,589
Charged to operations	$ 9,938	$18,746	$ 4,058
Charged to other income	19,282	32,451	46,531
Charged to cumulative effect	-	31,140	-
Recorded income tax expense	29,220	82,337	50,589
Income taxes applied against the debt component of AFUDC	-	-	1
Total income taxes	$29,220	$82,337	$50,590

Total income taxes differ from the amounts computed by applying the statutory federal income tax rate to income before taxes. The reasons for the differences were:

	For the Years Ended December 31,					
	1994		1993		1992	
	Amount	% of Pretax Income	Amount	% of Pretax Income	Amount	% of Pretax Income
	(Dollars in Thousands)					
Computed at statutory rate	$ 60,017	35.0	$100,673	35.0	$61,580	34.0
Increases (reductions) in tax resulting from:						
State income taxes net of federal income tax effect	7,821	4.6	12,119	4.2	7,963	4.4
Amortization of investment tax credits	(10,220)	(6.0)	(11,702)	(4.1)	(13,285)	(7.4)
Investment tax credit amortization - FERC settlement	(27,327)	(15.9)	-	-	-	-
Depreciation	(921)	(0.5)	(3,156)	(1.1)	(6,755)	(3.7)
Reversal of tax contingency	-	-	(3,771)	(1.3)	-	-
Flow-through/permanent differences	(208)	(0.1)	(7,669)	(2.7)	(1,407)	(0.8)
Other - net	58	-	(4,157)	(1.4)	2,493	1.4
Recorded income tax expense	29,220	17.1	82,337	28.6	50,589	27.9
Income taxes applied against debt component of AFUDC	-	-	-	-	1	-
Total income taxes	$ 29,220	17.1	$ 82,337	28.6	$50,590	27.9

Significant components of AP&L's net deferred tax liabilities as of December 31, 1994 and 1993, were (in thousands):

	1994	1993
Deferred tax liabilities:		
Net regulatory assets	$ (273,574)	$ (294,713)
Plant related basis differences	(465,787)	(458,023)
Rate deferrals	(183,700)	(229,714)
Bond reacquisition	(22,496)	(23,604)
Decontamination and decommissioning fund	(17,104)	(16,429)
Other	(20,317)	(21,414)
Total	$ (982,978)	$(1,043,897)
Deferred tax assets:		
Accumulated deferred investment tax credit	$ 46,506	$ 60,698
Nuclear refueling and maintenance	14,889	12,035
Alternative minimum tax credit	3,536	34,137
Standard coal plant	9,214	9,552
Other	24,232	18,490
Total	$ 98,377	$ 134,912
Net deferred tax liabilities	$ (884,601)	$ (908,985)

The alternative minimum tax (AMT) credit as of December 31, 1994, was $3.5 million. This AMT credit can be carried forward indefinitely and will reduce AP&L's federal income tax liability in future years.

In accordance with a System Energy FERC settlement, AP&L wrote off $27.3 million of unamortized deferred investment tax credits in 1994.

In 1993, AP&L adopted SFAS 109. SFAS 109 required that deferred income taxes be recorded for all temporary differences and carryforwards, and that deferred tax balances be based on enacted tax laws at tax rates that are expected to be in effect when the temporary differences reverse. SFAS 109 required that regulated enterprises recognize adjustments resulting from implementation as regulatory assets or liabilities if it is probable that such amounts will be recovered from or returned to customers in future rates. A substantial majority of the adjustments required by SFAS 109 was recorded to deferred tax balance sheet accounts with offsetting adjustments to regulatory assets and liabilities. As a result of the adoption of SFAS 109, 1993 net income was reduced by $2.6 million, assets were increased by $168.2 million, and liabilities were increased by $170.8 million. The cumulative effect of the adoption of SFAS 109 is included in income tax expense charged to operations.

NOTE 4. LINES OF CREDIT AND RELATED BORROWINGS

The SEC has authorized AP&L to effect short-term borrowings up to $125 million, which may be increased to as much as $243 million after further SEC approval. This authorization is effective through November 30, 1996. As of December 31, 1994, AP&L had outstanding short-term lines of credit of $34 million from banks within its service territory. Interest rates associated with these lines of credit generally are based on the prime rate, the London interbank offered rate, or a bid rate. Commitment fees on these lines of credit are .125% of the amount of available credit. In addition, AP&L can borrow from the Money Pool, subject to its maximum authorized level of short-term borrowings and the availability of funds. AP&L had no outstanding borrowings under the Money Pool arrangement as of December 31, 1994.

NOTE 5. PREFERRED STOCK

The number of shares and dollar value of AP&L's preferred stock were:

	As of December 31,				
	Shares Authorized and Outstanding		Total Dollar Value		Call Price Per Share as of December 31,
	1994	1993	1994	1993	1994
			(Dollars in Thousands)		
Without sinking fund:					
Cumulative, $100 par value:					
4.32% Series	70,000	70,000	$ 7,000	$ 7,000	$103.647
4.72% Series	93,500	93,500	9,350	9,350	$107.000
4.56% Series	75,000	75,000	7,500	7,500	$102.830
4.56% 1965 Series	75,000	75,000	7,500	7,500	$102.500
6.08% Series	100,000	100,000	10,000	10,000	$102.830
7.32% Series	100,000	100,000	10,000	10,000	$103.170
7.80% Series	150,000	150,000	15,000	15,000	$103.250
7.40% Series	200,000	200,000	20,000	20,000	$102.800
7.88% Series	150,000	150,000	15,000	15,000	$103.000
Cumulative, $25 par value:					
8.84% Series	400,000	400,000	10,000	10,000	$26.560
Cumulative, $0.01 par value:					
$2.40 Series(1)(2)	2,000,000	2,000,000	50,000	50,000	-
$1.96 Series(1)(2)	600,000	600,000	15,000	15,000	-
Total without sinking fund	4,013,500	4,013,500	$176,350	$176,350	
With sinking fund:					
Cumulative, $100 par value:					
10.60% Series	-	20,000	-	$ 2,000	-
8.52% Series	375,000	400,000	$ 37,500	40,000	$106.390
Cumulative, $25 par value:					
9.92% Series	641,085	721,085	16,027	18,027	$26.320
13.28% Series	200,000	400,000	5,000	10,000	$28.220
Total with sinking fund	1,216,085	1,541,085	$ 58,527	$ 70,027	

(1) The total dollar value represents the involuntary liquidation value of $25 per share.

(2) These series are not redeemable as of December 31, 1994.

The fair value of AP&L's preferred stock with sinking fund was estimated to be approximately $60.6 million and $74.7 million as of December 31, 1994 and 1993, respectively. The fair values were determined using quoted market prices or estimates from nationally recognized investment banking firms. See Note 1 for additional information on disclosure of fair value of financial instruments.

Changes in the preferred stock, with and without sinking fund, during the last three years were:

	Number of Shares		
	1994	1993	1992
Preferred stock issuances:			
$0.01 par value	-	-	600,000
Preferred stock retirements:			
$100 par value	(45,000)	(85,000)	(109,940)
$25 par value	(280,000)	(280,000)	(880,000)

Cash sinking fund requirements for the next five years for preferred stock outstanding as of December 31, 1994 are (in millions): 1995 - $9.5; 1996 - $4.5; 1997 - $4.5; 1998 - $4.5; and 1999 - $4.5. AP&L has the annual non-cumulative option to redeem, at par, additional amounts of certain series of its outstanding preferred stock.

NOTE 6. LONG-TERM DEBT

The long-term debt of AP&L as of December 31, 1994 and 1993, was:

Maturities		Interest Rates			
From	To	From	To	1994	1993
				(In Thousands)	
First Mortgage Bonds					
1995	1999	4-5/8%	9-3/4%	$ 100,960	$ 100,560
2000	2004	6%	9-3/4%	180,800	182,000
2005	2009	6.25%	7-1/2%	215,000	215,000
2019	2023	7%	10-3/8%	448,818	448,818
Governmental Obligations*					
1995	2008	6.125%	10%	53,120	83,290
2009	2021	6.25%	11%	234,004	202,193
Long-Term DOE Obligation (Note 8)				105,163	101,029
Unamortized Premium and Discount - Net				(15,811)	(16,555)
Total Long-Term Debt				1,322,054	1,316,335
Less Amount Due Within One Year				28,175	3,020
Long-Term Debt Excluding Amount Due Within One Year				$1,293,879	$1,313,315

* Consists of pollution control bonds, certain series of which are secured by non-interest bearing first mortgage bonds.

The fair value of AP&L's long-term debt, excluding long-term DOE obligation, as of December 31, 1994 and 1993 was estimated to be $1,133.6 million and $1,250.8 million, respectively. The fair values were determined using quoted market prices or estimates from nationally recognized investment banking firms. See Note 1 for additional information on disclosure of fair value of financial instruments.

For the years 1995, 1996, 1997, 1998 and 1999, AP&L has long-term debt maturities and cash sinking fund requirements (in millions) of $28.2, $28.0, $33.1, $18.7, and $1.2, respectively. In addition, other sinking fund requirements of approximately $.9 million annually may be satisfied by cash or by certification of property additions at the rate of 167% of such requirements.

NOTE 7. DIVIDEND RESTRICTIONS

The indenture relating to AP&L's long-term debt and provisions of its Amended and Restated Articles of Incorporation, as amended, relating to AP&L's preferred stock provide for restrictions on the payment of cash dividends or other distributions on common stock. As of December 31, 1994, $291.3 million of AP&L's retained earnings were restricted against the payment of cash dividends or other distributions on common stock. On February 1, 1995, AP&L paid Entergy Corporation a $32.8 million cash dividend on common stock.

NOTE 8. COMMITMENTS AND CONTINGENCIES

Capital Requirements and Financing

Construction expenditures (excluding nuclear fuel) for the years 1995, 1996, and 1997 are estimated to total $154.9 million each year. AP&L will also require $107 million during the period 1995-1997 to meet long-term debt and preferred stock maturities and sinking fund requirements. AP&L plans to meet the above requirements with internally generated funds and cash on hand. See Notes 5 and 6 regarding the possible refunding, redemption, purchase or other acquisition of certain outstanding series of preferred stock and long-term debt.

Unit Power Sales Agreement

System Energy has agreed to sell all of its 90% owned and leased share of capacity and energy from Grand Gulf 1 to AP&L, LP&L, MP&L, and NOPSI in accordance with specified percentages (AP&L 36%, LP&L 14%, MP&L 33%, and NOPSI 17%) as ordered by FERC. Charges under this agreement are paid in consideration for AP&L's respective entitlement to receive capacity and energy, and are payable irrespective of the quantity of energy delivered so long as the unit remains in commercial operation. The agreement will remain in effect until terminated by the parties and approved by FERC, most likely upon Grand Gulf 1's retirement from service. AP&L's monthly obligation for payments under the agreement is approximately $18 million.

Availability Agreement

AP&L, LP&L, MP&L, and NOPSI are individually obligated to make payments or subordinated advances to System Energy in accordance with stated percentages (AP&L 17.1%, LP&L 26.9%, MP&L 31.3%, and NOPSI 24.7%) in amounts that when added to amounts received under the Unit Power Sales Agreement or otherwise, are adequate to cover all of System Energy's operating expenses. System Energy has assigned its rights to payments and advances to certain creditors as security for certain obligations. Since commercial operation of Grand Gulf 1, payments under the Unit Power Sales Agreement have exceeded the amounts payable under the Availability Agreement. Accordingly, no payments have ever been required.

Reallocation Agreement

System Energy and AP&L, LP&L, MP&L, and NOPSI entered into the Reallocation Agreement relating to the sale of capacity and energy from the Grand Gulf Station and the related costs, in which LP&L, MP&L, and NOPSI agreed to assume all of AP&L's responsibilities and obligations with respect to the Grand Gulf Station under the Availability Agreement. FERC's decision allocating a portion of Grand Gulf 1 capacity and energy to AP&L supersedes the Reallocation Agreement as it relates to Grand Gulf 1. Responsibility for any Grand Gulf 2 amortization amounts has been individually allocated (LP&L 26.23%, MP&L 43.97%, and NOPSI 29.80%) under the terms of the Reallocation Agreement. However, the Reallocation Agreement does not affect AP&L's obligation to System Energy's lenders under the assignments referred to in the preceding paragraph. AP&L would be liable for its share of such amounts if LP&L, MP&L, and NOPSI were unable to meet their contractual obligations. No payments of any amortization amounts will be required as long as amounts paid to System Energy under the Unit Power Sales Agreement, including other funds available to System Energy, exceed amounts required under the Availability Agreement, which is expected to be the case for the foreseeable future.

System Fuels

AP&L has a 35% interest in System Fuels, a jointly owned subsidiary of AP&L, LP&L, MP&L, and NOPSI. The parent companies of System Fuels, including AP&L, agreed to make loans to System Fuels to finance its fuel procurement, delivery, and storage activities. As of December 31, 1994, AP&L had approximately $11 million of loans outstanding to System Fuels which mature in 2008.

In addition, System Fuels entered into a revolving credit agreement with a bank that provides $45 million in borrowings to finance System Fuels' nuclear materials and services inventory. Should System Fuels default on its obligations under its credit agreement, AP&L, LP&L, and System Energy have agreed to purchase nuclear materials and services financed under the agreement.

On April 30, 1993, AP&L assumed System Fuels' rights and obligations in connection with System Fuels' coal car leases. The other parent companies of System Fuels have been released from their obligations with respect to the coal car leases.

Coal

AP&L is a party to a contract for supply of coal from a mine in Wyoming and owns certain coal mining equipment and facilities at the mine. Based on estimated reserves, the mine is expected to provide the projected requirements of the Independence Station through at least 2011. AP&L has also agreed to purchase, over an approximate 20-year period beginning in 1980, 100 million tons of coal for use at the White Bluff Station, of which approximately 64 million have been purchased as of December 31, 1994.

Nuclear Insurance

The Price-Anderson Act limits public liability for a single nuclear incident to approximately $8.92 billion as of December 31, 1994. AP&L has protection for this liability through a combination of private insurance (currently $200 million) and an industry assessment program. Under the assessment program, the maximum amount that would be required for each nuclear incident would be $79.3 million per reactor, payable at a rate of $10 million per licensed reactor per incident per year. AP&L has two licensed reactors. In addition, AP&L participates in a private insurance program which provides coverage for worker tort claims filed for bodily injury

caused by radiation exposure. AP&L's maximum assessment under the program is an aggregate of approximately $6.4 million in the event losses exceed accumulated reserve funds.

AP&L is a member of certain insurance programs that provide coverage for property damage, including decontamination and premature decommissioning expense, to members' nuclear generating plants. As of December 31, 1994, AP&L was insured against such losses up to $2.75 billion, with $250 million of this amount designated to cover any shortfall in the NRC required decommissioning trust funding. In addition, AP&L is a member of an insurance program that covers certain replacement power and business interruption costs incurred due to prolonged nuclear unit outages. Under the property damage and replacement power/business interruption insurance programs, AP&L could be subject to assessments if losses exceed the accumulated funds available to the insurers. As of December 31, 1994, the maximum amount of such possible assessments to AP&L was $37.2 million.

The amount of property insurance presently carried by AP&L exceeds the NRC's minimum requirement for nuclear power plant licensees of $1.06 billion per site. NRC regulations provide that the proceeds of this insurance must be used, first, to place and maintain the reactor in a safe and stable condition and, second, to complete decontamination operations. Only after proceeds are dedicated for such use and regulatory approval is secured, would any remaining proceeds be made available for the benefit of plant owners or their creditors.

Spent Nuclear Fuel and Decommissioning Costs

AP&L provides for estimated future disposal costs for spent nuclear fuel in accordance with the Nuclear Waste Policy Act of 1982. AP&L entered into a contract with the DOE, whereby the DOE will furnish disposal service at a cost of one mill per net KWH generated and sold after April 7, 1983, plus a one-time fee for generation prior to that date. AP&L elected to pay the one-time fee, plus accrued interest, and has recorded a liability as of December 31, 1994, of approximately $105 million. The fees payable to the DOE may be adjusted in the future to assure full recovery. AP&L considers all costs incurred or to be incurred, except accrued interest, for the disposal of spent nuclear fuel to be proper components of nuclear fuel expense and provisions to recover such costs have been or will be made in applications to regulatory authorities.

Delays have occurred in the DOE's program for the acceptance and disposal of spent nuclear fuel at a permanent repository. In a statement released February 17, 1993, the DOE asserted that it does not have a legal obligation to accept spent nuclear fuel without an operational repository for which it has not yet arranged. Currently the DOE projects it will begin to accept spent fuel no earlier than 2010. In the meantime, AP&L is responsible for spent fuel storage. Current on-site spent fuel storage capacity at ANO is estimated to be sufficient until mid-1995, at which time an ANO storage facility using dry casks will begin operation. This facility is estimated to provide sufficient storage until 2000, with the capability of being expanded further as required. The initial cost of providing the additional on-site spent fuel storage capability required at ANO is $5 million to $10 million per unit. In addition, approximately $3 million to $5 million per unit will be required every two to three years subsequent to 1995 until the DOE's repository begins accepting ANO's spent fuel.

Entergy Operations and System Fuels joined in lawsuits against the DOE, seeking clarification of the DOE's responsibility to receive spent nuclear fuel beginning in 1998. The original suits, filed June 20, 1994, asked for a ruling stating that the Nuclear Waste Policy Act require the DOE to begin taking title to the spent fuel and to start removing it from nuclear power plants in 1998, a mandate for the DOE's nuclear waste management program to begin accepting fuel in 1998 and court monitoring of the program, and the potential for escrow of payments to the Nuclear Waste Fund instead of directly to the DOE.

AP&L is recovering in rates amounts sufficient to fund decommissioning costs for ANO, based on a 1994 interim update to the 1992 decommissioning cost study (in 1992 dollars), of approximately $806.3 million. The 1994 interim update adjusted the 1992 study only for increased cost of low level radioactive waste disposal. The amounts recovered in rates are deposited in external trust funds and reported at market value. The accumulated decommissioning liability of $137.4 million as of December 31, 1994, has been recorded in accumulated depreciation. Decommissioning expense in the amount of $12.2 million was recorded in 1994. AP&L regularly reviews and updates its estimates for decommissioning costs and applications will be made to the APSC to reflect in rates future changes in projected decommissioning costs. The actual decommissioning costs may vary from the estimates because of regulatory requirements, changes in technology, and increased costs of labor, materials, and equipment. Management believes that actual decommissioning costs are likely to be higher than the amounts presented above.

The staff of the SEC has questioned certain of the current accounting practices of the electric utility industry regarding the recognition, measurement, and classification of decommissioning costs for nuclear generating stations in the financial statements of electric utilities. In response to these questions, the FASB is currently reviewing the accounting for decommissioning. If current electric utility industry accounting practices for such decommissioning are changed, annual provisions for decommissioning could increase, the estimated cost for decommissioning could be recorded as a liability rather than as accumulated depreciation, and trust fund income from the external decommissioning trusts could be reported as investment income.

The EPAct has a provision that assesses domestic nuclear utilities with fees for the decontamination and decommissioning of the DOE's past uranium enrichment operations. The decontamination and decommissioning assessments will be used to set up a fund into which contributions from utilities and the federal government will be placed. AP&L's annual assessment, which will be adjusted annually for inflation, is $3.4 million (in 1995 dollars) annually for approximately 15 years. FERC requires that utilities treat these assessments as costs of fuel as they are amortized. The cumulative liability of $38.9 million as of December 31, 1994, is recorded in other current liabilities and other noncurrent liabilities, and is offset in the financial statements by a regulatory asset.

ANO Matters

ANO 2 experienced a forced outage for repair of certain steam generator tubes in March 1992. Further inspections and repairs were conducted at subsequent refueling and mid-cycle outages in September 1992, May 1993, April 1994, and January 1995. AP&L's budgeted maintenance expenditures were adequate to cover the cost of such repairs. ANO 2's output has been reduced 15 megawatts or 1.6% due to secondary side fouling, tube plugging, and reduction of primary temperature. Entergy Operations continues to take steps at ANO 2 to reduce the number and severity of future tube cracks. In addition, Entergy Operations continues to meet with the NRC to discuss such steps and results of inspections of the steam generator tubes, as well as the timing of future inspections. Additional inspections are planned for the normal refueling outage scheduled for October 1995.

NOTE 9. LEASES

As of December 31, 1994, AP&L had capital leases and noncancelable operating leases (excluding the nuclear fuel lease) with minimum lease payments as follows:

	Capital Leases	Operating Leases
	(In Thousands)	
1995	$ 13,539	$ 28,303
1996	11,126	24,217
1997	8,293	15,566
1998	8,293	15,144
1999	8,294	11,552
Years thereafter	48,695	50,685
Minimum lease payments	98,240	$145,467
Less: Amount representing interest	40,587	
Present value of net minimum lease payments	$ 57,653	

Rental expense for capital and operating leases (excluding the nuclear fuel lease) amounted to approximately $26.4 million, $23.2 million, and $27.4 million in 1994, 1993, and 1992, respectively.

Nuclear Fuel Lease

AP&L has an arrangement to lease nuclear fuel in an amount up to $125 million. The lessor finances its acquisition of nuclear fuel through a credit agreement and the issuance of notes. The credit agreement, which was entered into in 1988, has been extended to December 1997 and the notes have varying remaining maturities of up to 3 years. It is expected that these arrangements will be extended or alternative financing will be secured by the lessor upon the maturity of the current arrangements, based on AP&L's nuclear fuel requirements. If the lessor cannot arrange financing upon maturity of its borrowings, AP&L must purchase nuclear fuel in an amount sufficient to enable the lessor to retire such borrowings.

Lease payments are based on nuclear fuel use. Nuclear fuel lease expense of $56.2 million, $69.7 million, and $65.5 million (including interest of $7.5 million, $10.6 million, and $11.6 million) was charged to operations in 1994, 1993, and 1992, respectively.

NOTE 10. POSTRETIREMENT BENEFITS

Pension Plan

AP&L has a defined benefit pension plan covering substantially all of its employees. The pension plan is noncontributory and provides pension benefits that are based on employees' credited service and average compensation, generally during the last five years before retirement. AP&L funds pension costs in accordance with contribution guidelines established by the Employee Retirement Income Security Act of 1974, as amended, and the Internal Revenue Code of 1986, as amended. The assets of the plan consist primarily of common and preferred stocks, fixed income securities, interest in a money market fund, and insurance contracts.

Effective June 6, 1990, AP&L's nuclear operations employees became employees of Entergy Operations. However, the employees still remain under AP&L's plan and no transfers of related pension liabilities and assets have been made.

AP&L's 1994, 1993, and 1992 pension cost, including amounts capitalized, included the following components:

	For the Years Ended December 31,		
	1994	1993	1992
		(In Thousands)	
Service cost - benefits earned during the period	$ 8,854	$ 7,940	$ 6,906
Interest cost on projected benefit obligation	22,651	21,744	20,512
Actual return on plan assets	365	(31,984)	(16,765)
Net amortization and deferral	(24,474)	10,531	(3,531)
Other	-	-	-
Net pension cost	$ 7,396	$ 8,231	$ 7,122

The funded status of AP&L's pension plan as of December 31, 1994 and 1993, was:

	1994	1993
	(In Thousands)	
Actuarial present value of accumulated pension plan benefits:		
Vested	$238,769	$255,955
Nonvested	1,797	1,724
Accumulated benefit obligation	$240,566	$257,679
Plan assets at fair value	$283,437	$288,418
Projected benefit obligation	283,256	316,255
Plan assets greater (less than) projected benefit obligation	181	(27,837)
Unrecognized prior service cost	6,568	5,841
Unrecognized transition asset	(16,350)	(18,686)
Unrecognized net loss (gain)	(12,453)	13,242
Accrued pension liability	$(22,054)	$(27,440)

The significant actuarial assumptions used in computing the information above for 1994, 1993, and 1992 were as follows: weighted average discount rate, 8.5% for 1994, 7.5% for 1993 and 8.25% for 1992; weighted average rate of increase in future compensation levels, 5.1% for 1994 and 5.6% for 1993 and 1992 and expected long-term rate of return on plan assets, 8.5%. Transition assets are being amortized over 15 years.

Other Postretirement Benefits

AP&L also provides certain health care and life insurance benefits for retired employees. Substantially all employees may become eligible for these benefits if they reach retirement age while still working for AP&L. The cost of providing these benefits, recorded on a cash basis, to retirees in 1992 was approximately $3.5 million.

Effective January 1, 1993, AP&L adopted SFAS 106. This standard required a change from a cash method to an accrual method of accounting for postretirement benefits other than pensions. AP&L continues to fund these benefits on a pay-as-you-go basis. As of January 1, 1993, the actuarially determined accumulated

postretirement benefit obligation (APBO) earned by retirees and active employees was estimated to be approximately $80.5 million. This obligation is being amortized over a 20-year period beginning in 1993. AP&L has received an order from the APSC permitting deferral, as a regulatory asset, of the increased annual expense associated with these benefits.

AP&L's 1994 and 1993 postretirement benefit cost, including amounts capitalized and deferred, included the following components:

	1994	1993
	(In Thousands)	
Service cost - benefits earned during the period	$ 3,080	$ 2,366
Interest cost on APBO	5,510	6,427
Actual return on plan assets	-	(71)
Net amortization and deferral	3,833	3,954
Net postretirement benefit cost	$ 12,423	$ 12,676

The funded status of AP&L's pension plan as of December 31, 1994 and 1993, was:

	1994	1993
	(In Thousands)	
Accumulated postretirement benefit obligation:		
Retirees	$ 49,291	$ 59,906
Other fully eligible participants	9,876	8,366
Other active participants	12,204	25,038
	71,371	93,310
Plan assets at fair value	-	354
Plan assets less than APBO	(71,371)	(92,956)
Unrecognized transition obligation	71,160	75,114
Unrecognized net loss (gain)	(16,272)	8,360
Accrued postretirement benefit liability	$(16,483)	$ (9,482)

The assumed health care cost trend rate used in measuring the APBO was 9.4% for 1995, gradually decreasing each successive year until it reaches 5.0% in 2011. A one percentage-point increase in the assumed health care cost trend rate for each year would have increased the APBO as of December 31, 1994, by 8.2% and the sum of the service cost and interest cost by approximately 10.8%. The assumed discount rate and rate of increase in future compensation used in determining the APBO were 8.5% for 1994 and 7.5% for 1993 and 5.1% for 1994 and 5.5% for 1993, respectively.

NOTE 11. TRANSACTIONS WITH AFFILIATES

AP&L buys electricity from and/or sells electricity to the other System operating companies, System Energy, and Entergy Power under rate schedules filed with FERC. In addition, AP&L purchases fuel from System Fuels, receives technical and advisory services from Entergy Services, and receives management and operating services from Entergy Operations.

Operating revenues include revenues from sales to affiliates amounting to $238.7 million in 1994, $181.8 million in 1993, and $211.4 million in 1992. Operating expenses include charges from affiliates for fuel costs, purchased power and related charges, management services, and technical and advisory services totaling $310.7 million in 1994, $323.2 million in 1993, and $573.4 million in 1992. Operating expenses also include $25.7 million in 1994, $16.8 million in 1993, and $47.4 million in 1992, for power purchased from Entergy Power. AP&L pays directly or reimburses Entergy Operations for the costs associated with operating ANO (excluding nuclear fuel), which were approximately $221.2 million in 1994, $226.3 million in 1993, and $292.3 million in 1992.

NOTE 12. RESTRUCTURING COSTS

During the third quarter of 1994, AP&L announced a restructuring program related to certain of its operating units. The program is designed to reduce costs, improve operating efficiencies, and increase shareholder value in order to enable AP&L to become a low-cost producer. The program includes reductions in the number of employees and the consolidation of offices and facilities. In 1994, AP&L recorded restructuring charges of $12.5 million. These charges primarily include employee severance costs related to the expected termination of approximately 696 employees. As of December 31, 1994, 35 AP&L employees were terminated under the program at a severance cost of $0.3 million.

NOTE 13. QUARTERLY FINANCIAL DATA (UNAUDITED)

AP&L's business is subject to seasonal fluctuations with the peak period occurring during the third quarter. Operating results for the four quarters of 1994 and 1993 were:

	Operating Revenues	Operating Income	Net Income
		(In Thousands)	
1994:			
First Quarter	$ 371,091	$ 44,674	$ 26,388
Second Quarter	$ 414,901	$ 59,581	$ 41,763
Third Quarter	$ 470,770	$ 56,163	$ 36,630
Fourth Quarter	$ 333,980	$ 56,215	$ 37,482
1993:			
First Quarter	$ 346,740	$ 36,961	$ 66,081
Second Quarter	$ 383,651	$ 53,332	$ 34,572
Third Quarter	$ 519,822	$101,484	$ 81,677
Fourth Quarter	$ 341,355	$ 44,445	$ 22,967

See Note 1 for information regarding the recording of the cumulative effect of the change in accounting principle for unbilled revenues in January 1993.

ARKANSAS POWER & LIGHT COMPANY

SELECTED FINANCIAL DATA - FIVE-YEAR COMPARISON

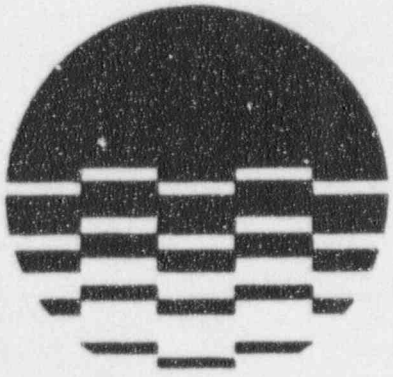
	1994	1993	1992	1991	1990
			(In Thousands)		
Operating revenues	$1,590,742	$1,591,568	$1,521,129	$1,528,270	$1,481,408
Income before cumulative effect of a change in accounting principle	$ 142,263	$ 155,110	$ 130,529	$ 143,451	$ 129,765
Total assets	$4,292,215	$4,334,105	$4,038,811	$4,192,020	$4,137,938
Long-term obligations (1)	$1,446,940	$1,478,203	$1,453,588	$1,670,678	$1,731,212

(1) Includes long-term debt (excluding currently maturing debt), preferred stock with sinking fund, and noncurrent capital lease obligations.

See Notes 1, 3, and 10 for the effect of accounting changes in 1993.

	1994	1993	1992	1991	1990
			(Dollars in Thousands)		
Operating Revenues:					
Residential	$ 506,160	$ 528,734	$ 476,090	$ 494,375	$ 484,359
Commercial	307,296	306,742	291,367	289,291	283,971
Industrial	338,988	336,856	325,569	324,632	331,929
Governmental	16,698	16,670	17,700	19,731	19,599
Total retail	1,169,142	1,189,002	1,110,726	1,128,029	1,119,858
Sales for resale	395,234	379,480	385,028	373,735	339,366
Other	26,366	23,086	25,375	26,506	22,184
Total	$1,590,742	$1,591,568	$1,521,129	$1,528,270	$1,481,408
Billed Electric Energy Sales (Millions of KWH):					
Residential	5,522	5,680	5,102	5,564	5,401
Commercial	4,147	4,067	3,841	3,967	3,821
Industrial	5,941	5,690	5,509	5,565	5,532
Governmental	231	230	248	290	285
Total retail	15,841	15,667	14,700	15,386	15,039
Sales for resale	15,497	13,950	15,413	16,087	13,618
Total	31,338	29,617	30,113	31,473	28,657

Gulf States Utilities Company/1994 Financial Statements



GSU

GULF STATES UTILITIES COMPANY

DEFINITIONS

Certain abbreviations or acronyms used in GSU's Financial Statements, Notes to Financial Statements, and Management's Financial Discussion and Analysis are defined below:

Abbreviation or Acronym	Term
AFUDC	Allowance for Funds Used During Construction
AP&L	Arkansas Power & Light Company
Cajun	Cajun Electric Power Cooperative, Inc.
DOE	United States Department of Energy
Entergy or System	Entergy Corporation and its various direct and indirect subsidiaries
Entergy Operations	Entergy Operations, Inc., a subsidiary of Entergy that has operating responsibility for Grand Gulf 1, River Bend, Waterford 3, and Arkansas Nuclear One Steam Electric Generating Station
Entergy Power	Entergy Power, Inc., a subsidiary of Entergy Corporation that markets capacity and energy for resale from certain generating facilities to other parties, principally non-affiliates
Entergy Services	Entergy Services, Inc.
EPAct	The Energy Policy Act of 1992
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
GSU	Gulf States Utilities Company (including wholly owned subsidiaries - Varibus Corporation, GSG&T, Inc., Prudential Oil and Gas, Inc., and Southern Gulf Railway Company)
KWH	Kilowatt-Hour(s)
LP&L	Louisiana Power & Light Company
LPSC	Louisiana Public Service Commission
Money Pool	Entergy Money Pool, which allows certain System companies to borrow from, or lend to, certain other System companies
MP&L	Mississippi Power & Light Company

Abbreviation or Acronym	Term
Merger	The combination transaction consummated on December 31, 1993, by which GSU became a subsidiary of Entergy Corporation and Entergy Corporation became a Delaware corporation
NOPSI	New Orleans Public Service Inc.
PUCT	Public Utility Commission of Texas
Rate Cap	The level of retail electric base rates in effect at December 31, 1993, for the Louisiana retail jurisdiction, and the level in effect prior to the Texas Cities Rate Settlement for the Texas retail jurisdiction, that may not be exceeded for the five years following December 31, 1993
River Bend	River Bend Steam Electric Generating Station (nuclear), owned 70% by GSU
RUS	Rural Utility Services (formerly the Rural Electrification Administration or "REA")
SEC	Securities and Exchange Commission
SFAS	Statement of Financial Accounting Standards promulgated by the FASB
SFAS 106	SFAS 106, "Employers' Accounting for Postretirement Benefits Other Than Pensions"
SFAS 109	SFAS 109, "Accounting for Income Taxes"
System or Entergy	Entergy Corporation and its various direct and indirect subsidiaries
System Agreement	Agreement, effective January 1, 1983, as amended among the System operating companies relating to the sharing of generating capacity and other power resources
System operating companies	AP&L, GSU, LP&L, MP&L, and NOPSI, collectively

GULF STATES UTILITIES COMPANY

REPORT OF MANAGEMENT

The management of Gulf States Utilities Company has prepared and is responsible for the financial statements and related financial information included herein. The financial statements are based on generally accepted accounting principles. Financial information included elsewhere in this report is consistent with the financial statements.

To meet its responsibilities with respect to financial information, management maintains and enforces a system of internal accounting controls that is designed to provide reasonable assurance, on a cost-effective basis, as to the integrity, objectivity, and reliability of the financial records, and as to the protection of assets. This system includes communication through written policies and procedures, an employee Code of Conduct, and an organizational structure that provides for appropriate division of responsibility and the training of personnel. This system is also tested by a comprehensive internal audit program.

The independent public accountants provide an objective assessment of the degree to which management meets its responsibility for fairness of financial reporting. They regularly evaluate the system of internal accounting controls and perform such tests and other procedures as they deem necessary to reach and express an opinion on the fairness of the financial statements.

Management believes that these poli. es and procedures provide reasonable assurance that its operations are carried out with a high standard of business conduct.

EDWIN LUPBERGER
Chairman and Chief Executive Officer

GERALD D. MCINVALE
Senior Vice President and
Chief Financial Officer

GULF STATES UTILITIES COMPANY

AUDIT COMMITTEE CHAIRMAN'S LETTER

The Entergy Corporation Board of Directors' Audit Committee functions as the Audit Committee for Gulf States Utilities Company. The Audit Committee is comprised of four directors, who are not officers of GSU: H. Duke Shackelford (Chairman), Lucie J. Fjeldstad, Dr. Norman C. Francis, and James R. Nichols. The committee held four meetings during 1994.

The Audit Committee oversees GSU's financial reporting process on behalf of the Board of Directors and provides reasonable assurance to the Board that sufficient operating, accounting, and financial controls are in existence and are adequately reviewed by programs of internal and external audits.

The Audit Committee discussed with Entergy's internal auditors and the independent public accountants (Coopers & Lybrand L.L.P.) the overall scope and specific plans for their respective audits, as well as GSU's financial statements and the adequacy of GSU's internal controls. The committee met, together and separately, with Entergy's internal auditors and independent public accountants, without management present, to discuss the results of their audits, their evaluation of GSU's internal controls, and the overall quality of GSU's financial reporting. The meetings also were designed to facilitate and encourage any private communication between the committee and the internal auditors or independent public accountants.

H. DUKE SHACKELFORD
Chairman, Audit Committee

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REPORT OF INDEPENDENT ACCOUNTANTS

To the the Board of Directors and Shareholders of
Gulf States Utilities Company

We have audited the accompanying balance sheets of Gulf States Utilities Company as of December 31, 1994 and 1993 and the related statements of income (loss), retained earnings and paid-in-capital and cash flows for each of the three years in the period ended December 31, 1994. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with generally accepted auditing standards. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in Note 13 to the financial statements, the common stock of the Company was acquired on December 31, 1993.

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 1994 and 1993, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 1994 in conformity with generally accepted accounting principles.

As discussed in Note 2 to the financial statements, the net amount of capitalized costs for River Bend Unit 1 Nuclear Generating Plant (River Bend) exceed those costs currently being recovered through rates. At December 31, 1994, approximately $685 million is not currently being recovered through rates. If current regulatory and court orders are not modified, a write-off of all or a portion of such costs may be required. Additionally, as discussed in Note 2 to the financial statements, other rate-related contingencies exist which may result in refunds of revenues previously collected. The extent of such write-off of capitalized River Bend costs or refund of revenues previously collected, if any, will not be determined until appropriate rate proceedings and court appeals have been concluded. Accordingly, the accompanying financial statements do not include any adjustments or provision for write-off or refund that might result from the outcome of these uncertainties.

As discussed in Note 8 to the financial statements, civil actions have been initiated against the Company to, among other things, recover the co-owner's investment in River Bend and to annul the River Bend Joint Ownership Participation and Operating Agreement. The ultimate outcome of these proceedings cannot presently be determined.

As discussed in Note 3 to the financial statements, in 1993, the Company adopted Statement of Financial Accounting Standards No. 109, "Accounting for Income Taxes". As discussed in Note 10 to the financial statements, the Company adopted Statement of Financial Accounting Standards No. 106, "Employers' Accounting for Postretirement Benefits Other Than Pensions", as of January 1, 1993. As discussed in Note 1 to the financial statements, as of January 1, 1993, the Company began accruing revenues for energy delivered to customers but not yet billed. As discussed in Note 1 to the financial statements, the Company changed its accounting for power plant materials and supplies as of January 1, 1992.

COOPERS & LYBRAND L.L.P.
New Orleans, Louisiana
February 21, 1995, except for the last paragraph
of "Filings with the PUCT and Texas Cities" in
Note 2, as to which the date is March 20, 1995

GULF STATES UTILITIES COMPANY
BALANCE SHEETS
ASSETS

	December 31,	
	1994	1993
	(In Thousands)	
Utility Plant:		
Electric	$6,842,726	$6,825,989
Natural gas	44,505	42,786
Steam products	77,307	75,689
Property under capital leases	82,914	86,039
Construction work in progress	96,176	50,080
Nuclear fuel under capital leases	80,042	94,828
Total	7,223,670	7,175,411
Less - accumulated depreciation and amortization	2,504,826	2,323,804
Utility plant - net	4,718,844	4,851,607
Other Property and Investments:		
Decommissioning trust fund	21,309	17,873
Other - at cost (less accumulated depreciation)	29,315	29,360
Total	50,624	47,233
Current Assets:		
Cash and cash equivalents:		
Cash	8,063	3,012
Temporary cash investments - at cost, which approximates market		
Associated companies	5,085	-
Other	91,496	258,337
Total cash and cash equivalents	104,644	261,349
Accounts receivable:		
Customer (less allowance for doubtful accounts of $0.7 million in 1994 and $2.4 million in 1993)	167,745	117,369
Associated companies	12,732	-
Other	20,706	18,371
Accrued unbilled revenues	39,470	32,572
Deferred fuel costs	6,314	5,883
Accumulated deferred income taxes	49,457	-
Fuel inventory	25,784	23,448
Materials and supplies - at average cost	90,054	86,831
Rate deferrals	100,478	90,775
Prepayments and other	13,754	48,948
Total	631,138	685,546
Deferred Debits and Other Assets:		
Regulatory Assets:		
Rate deferrals	506,974	638,015
SFAS 109 regulatory asset - net	426,358	432,411
Unamortized loss on reacquired debt	63,994	70,970
Other regulatory assets	35,168	40,690
Long-term receivables	264,752	218,079
Other	145,609	152,800
Total	1,442,855	1,552,965
TOTAL	$6,843,461	$7,137,351

See Notes to Financial Statements.

GULF STATES UTILITIES COMPANY
BALANCE SHEETS
CAPITALIZATION AND LIABILITIES

	December 31,	
	1994	1993
	(In Thousands)	
Capitalization:		
Common stock, no par value, authorized 200,000,000 shares; issued and outstanding 100 shares in 1994 and 1993	$114,055	$114,055
Paid-in capital	1,152,336	1,152,304
Retained earnings	264,626	666,401
Total common shareholder's equity	1,531,017	1,932,760
Preference stock	150,000	150,000
Preferred stock:		
Without sinking fund	136,444	136,444
With sinking fund	94,934	101,004
Long-term debt	2,318,417	2,368,639
Total	4,230,812	4,688,847
Other Noncurrent Liabilities:		
Obligations under capital leases	125,691	152,359
Other	68,753	65,259
Total	194,444	217,618
Current Liabilities:		
Currently maturing long-term debt	50,425	425
Accounts payable:		
Associated companies	31,722	2,745
Other	140,975	109,840
Customer deposits	22,216	21,958
Taxes accrued	12,478	22,856
Interest accrued	55,327	59,516
Nuclear refueling reserve	10,117	22,356
Obligations under capital leases	37,265	41,713
Reserve for rate refund	56,972	-
Other	111,963	97,741
Total	529,460	379,150
Deferred Credits:		
Accumulated deferred income taxes	1,100,396	1,062,180
Accumulated deferred investment tax credits	199,428	255,274
Deferred River Bend finance charges	82,406	106,765
Other	506,515	427,517
Total	1,888,745	1,851,736
Commitments and Contingencies (Notes 2, 8, and 9)		
TOTAL	$6,843,461	$7,137,351

See Notes to Financial Statements.

GULF STATES UTILITIES COMPANY
STATEMENTS OF CASH FLOWS

	For the Years Ended December 31,		
	1994	1993	1992
		(In Thousands)	
Operating Activities:			
Net income (loss)	($82,755)	$78,862	$133,848
Noncash items included in net income (loss):			
Extraordinary items	-	1,259	9,597
Cumulative effect of a change in accounting principle	-	(10,660)	(4,032)
Change in rate deferrals	96,979	61,115	52,946
Depreciation and decommissioning	197,151	190,405	188,393
Deferred income taxes and investment tax credits	(62,171)	41,302	50,238
Allowance for equity funds used during construction	(1,334)	(726)	(1,226)
Write-off of plant held for future use	85,476	-	-
Changes in working capital:			
Receivables	(72,341)	6,879	4,373
Fuel inventory	(2,336)	(2,289)	(4,152)
Accounts payable	60,112	11,072	(1,171)
Taxes accrued	(10,378)	3,764	(2,634)
Interest accrued	(4,189)	(2,497)	(15,276)
Reserve for rate refund	56,972	-	-
Other working capital accounts	33,781	(9,915)	(13,675)
Decommissioning trust contributions	(3,202)	(2,710)	(5,912)
Purchased power settlement	-	(169,300)	(20,797)
Other	34,594	58,874	(22,992)
Net cash flow provided by operating activities	326,359	255,435	347,528
Investing Activities:			
Construction expenditures	(155,989)	(115,481)	(97,377)
Proceeds received from sale of property	-	-	12,460
Allowance for equity funds used during construction	1,334	726	1,226
Nuclear fuel purchases	(31,178)	(2,118)	-
Proceeds from sale/leaseback of nuclear fuel	29,386	2,118	-
Refund of escrow account and other property	-	5,921	13,091
Net cash flow used in investing activities	(156,447)	(108,834)	(70,600)
Financing Activities:			
Proceeds from the issuance of:			
First mortgage bonds	-	338,379	1,185,260
Other long-term debt	101,109	21,440	48,965
Preference stock	-	146,625	-
Retirement of:			
First mortgage bonds	-	(360,199)	(1,067,717)
Other long-term debt	(102,425)	(18,398)	(127,161)
Redemption of preferred and preference stock	(6,070)	(174,841)	(174,226)
Dividends paid:			
Common stock	(289,100)	-	-
Preferred and preference stock	(30,131)	(35,999)	(237,369)
Net cash flow used in financing activities	(326,617)	(82,993)	(372,248)
Net increase (decrease) in cash and cash equivalents	(156,705)	63,608	(95,320)
Cash and cash equivalents at beginning of period	261,349	197,741	293,061
Cash and cash equivalents at end of period	$104,644	$261,349	$197,741
SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION:			
Cash paid during the period for:			
Interest - net of amount capitalized	$191,850	$197,058	$239,607
Income taxes	$251	$15,600	$8,000
Noncash investing and financing activities:			
Capital lease obligations incurred	$31,178	$17,143	$87,022
Deficiency of fair value of decommissioning trust assets over amount invested	($915)	-	-

See Notes to Financial Statements.

GULF STATES UTILITIES COMPANY

MANAGEMENT'S FINANCIAL DISCUSSION AND ANALYSIS

LIQUIDITY AND CAPITAL RESOURCES

Liquidity is important to GSU due to the capital intensive nature of its business, which requires large investments in long-lived assets. While large capital expenditures for the construction of new generating capacity are not currently planned, GSU does require significant capital resources for the periodic maturity of certain series of debt and preferred stock and ongoing construction expenditures. Net cash flow from operations totaled $326 million, $255 million, and $348 million in 1994, 1993, and 1992, respectively. Cash flow from operations in 1993 includes nonrecurring items related to the payment of $169.3 million as a result of the settlement of a purchased power dispute. In recent years, this cash flow, supplemented by cash on hand, has been sufficient to meet substantially all investing and financing requirements, including capital expenditures, dividends, and debt/preferred stock maturities. GSU's ability to fund these capital requirements with cash from operations, results in part from continued efforts to reduce costs as well as collections under River Bend rate phase-in plan of previously deferred amounts. (In the income statement, these revenue collections are offset by the amortization of previously deferred costs; therefore, there is no effect on net income.) The River Bend rate phase-in plan will continue to contribute to GSU's cash position through 1998. See Note 2 for additional information on GSU's rate phase-in plan. Further, GSU has the ability to meet future capital requirements through future debt and preference stock issuances, as discussed below. See Note 8 for additional information on GSU's capital and refinancing requirements in 1995 - 1997. Also, to the extent current market interest and dividend rates allow, GSU may continue to refinance high-cost debt and preferred stock prior to maturity.

In 1994, GSU paid to Entergy Corporation approximately $289.1 million of cash dividends on its common stock. Prior to 1994, GSU had not paid any cash dividends on its common stock since June 1986.

On March 20, 1995, the PUCT ordered GSU to implement a $72.9 million annual base rate reduction for the period March 31, 1994, through September 1, 1994, decreasing to an annual base rate reduction of $52.9 million after September 1, 1994. In accordance with the Merger agreement, the rate reduction is applied retroactively to March 31, 1994. As a result, GSU recorded a $57 million reserve for reserve for rate refund in 1994. See Note 2 for additional information.

Earnings coverage tests and bondable property additions limit the amount of first mortgage bonds and preferred stock that GSU can issue. As a result of the charges recorded in 1994 as discussed in Notes 12 and 13, GSU was precluded from issuing first mortgage bonds under its earnings coverage test as of December 31, 1994. As of December 31, 1994, GSU was unable to issue any additional preferred stock. There are no limitations on the issuance of preference stock. However, GSU has the ability to issue approximately $578 million of first mortgage bonds against the retirement of first mortgage bonds without satisfying an earnings coverage test.

See Notes 5 and 6 for information on GSU's financing activities and Note 4 for information on GSU's short-term borrowings and lines of credit.

See Notes 2 and 8 for information regarding litigation with Cajun, and River Bend rate appeals. Substantial write-offs or charges resulting from adverse rulings in these matters could result in substantial additional net losses being reported by GSU in 1995 and subsequent periods, with resulting substantial adverse adjustments to common shareholder's equity. Also, adverse resolution of these matters could adversely affect GSU's ability to continue to pay dividends and obtain financing, which could in turn affect GSU's liquidity.

GULF STATES UTILITIES COMPANY
STATEMENTS OF INCOME (LOSS)

	For the Years Ended December 31,		
	1994	1993	1992
		(In Thousands)	
Operating Revenues:			
Electric	$1,719,201	$1,747,961	$1,694,536
Natural gas	31,605	32,466	28,523
Steam products	46,559	47,193	50,315
Total	1,797,365	1,827,620	1,773,374
Operating Expenses:			
Operation and maintenance:			
Fuel, fuel-related expenses and gas purchased for resale	517,177	559,416	488,436
Purchased power	203,773	134,936	136,716
Nuclear refueling outage expenses	12,684	10,706	29,087
Other operation and maintenance	494,865	458,677	409,378
Depreciation and amortization	197,151	190,405	188,393
Taxes other than income taxes	98,096	95,742	91,740
Income taxes	(6,448)	46,007	38,058
Amortization of rate deferrals	66,416	61,115	52,946
Total	1,583,714	1,557,004	1,434,754
Operating Income	213,651	270,616	338,620
Other Income (Deductions):			
Allowance for equity funds used during construction	1,334	726	1,226
Write-off of plant held for future use	(85,476)	-	-
Miscellaneous - net	(64,843)	19,996	64,837
Income taxes	55,638	(12,009)	(17,801)
Total	(93,347)	8,713	48,262
Interest Charges:			
Interest on long-term debt	195,414	202,235	239,341
Other interest - net	8,720	8,364	9,075
Allowance for borrowed funds used during construction	(1,075)	(731)	(947)
Total	203,059	209,868	247,469
Income (Loss) before Extraordinary Items and the Cumulative Effect of Accounting Changes	(82,755)	69,461	139,413
Extraordinary Items (net of income taxes)	-	(1,259)	(9,597)
Cumulative Effect of Accounting Changes (net of income taxes) (Note 1)	-	10,660	4,032
Net Income (Loss)	(82,755)	78,862	133,848
Preferred and Preference Stock Dividend Requirements and Other	29,919	35,581	49,702
Earnings (Loss) Applicable to Common Stock	($112,674)	$43,281	$84,146

See Notes to Financial Statements.

GULF STATES UTILITIES COMPANY
STATEMENTS OF RETAINED EARNINGS AND PAID-IN CAPITAL

	For the Years Ended December 31,		
	1994	1993	1992
		(In Thousands)	
Retained Earnings, January 1	$666,401	$631,462	$667,893
Add:			
Net income (loss)	(82,755)	78,862	133,848
Total	583,646	710,324	801,741
Deduct:			
Dividends declared:			
Preferred and preference stock	29,831	35,581	158,547
Common stock	289,100	-	-
Preferred and preference stock redemption	89	8,342	11,732
Total	319,020	43,923	170,279
Retained Earnings, December 31 (Note 7)	$264,626	$666,401	$631,462
Paid-in Capital, January 1	$1,152,304	$67,316	$73,993
Add:			
Issuance of 100 shares of no par common stock with a stated value of $114,055 net of the retirement of 114,055,065 shares of no par common stock	-	1,086,868	-
Gain (loss) on reacquisition of preferred and preference stock	32	(1,880)	(6,677)
Paid-in Capital, December 31	$1,152,336	$1,152,304	$67,316

See Notes to Financial Statements.

Net Income

GSU incurred a net loss for the year 1994 due primarily to write-offs and charges associated with the resolution of certain contingencies and additional Merger-related costs aggregating $137 million (see Note 13), a base rate reduction ordered by the PUCT applied retroactively to March 1994 (see Note 2), and restructuring costs (see Note 12). Net income decreased in 1993 due primarily to Merger-related charges recorded at year-end. Also contributing to the decrease was a rate refund and one-time credit resulting from a November 1993 rate settlement, the effect of implementing SFAS 106, and the impact in 1992 of reducing a purchased power settlement liability. The decrease in net income was partially offset by the one-time recording of the cumulative effect of the change in accounting principle for unbilled revenues and its ongoing effects. Effective January 1, 1993, GSU began accruing as revenues the charges for energy delivered to customers but not yet billed. Electric and gas revenues were previously recorded on a cycle-billing basis. Excluding the above mentioned items, net income for 1993 would have been $139.2 million, an increase of $29.6 million which is due primarily to increased retail energy sales and decreased interest expense.

Significant factors affecting the results of operations and causing variances between the years 1994 and 1993, and 1993 and 1992 are discussed under "Revenues and Sales," "Expenses," and "Other" below.

Revenues and Sales

Operating revenues decreased in 1994 due primarily to a base rate reduction ordered by the PUCT applied retroactively to March 1994 (see Note 2) and lower retail fuel revenues partially offset by increased wholesale revenues associated with higher sales for resale and increased retail base revenue. The decrease in retail revenues is primarily due to a decrease in fuel recovery revenue and a November 1993 rate reduction in Texas. Energy sales increased due primarily to higher sales for resale as a result of GSU's participation in the System power pool.

Operating revenues were higher in 1993 due primarily to increased residential and commercial energy sales resulting primarily from a return to more normal weather as compared to milder weather in 1992, and increased fuel adjustment revenues and collections of previously deferred River Bend costs, neither of which affects net income. These increases were partially offset by a refund and one-time credit to Texas retail customers resulting from a rate settlement.

See "Selected Financial Data - Five-Year Comparison," following the notes, for information on operating revenues by source and KWH sales.

Expenses

Operating expenses increased in 1994 due primarily to higher purchased power and other operation and maintenance expenses, partially offset by lower fuel for electric generation and fuel-related expense and lower income tax expense. Purchased power increased in 1994 due to GSU's participation in joint dispatching through the System power pool resulting from increased energy sales as discussed above. In addition, the increase in purchased power expense in 1994 was also due to the recording of a provision for refund of disallowed purchased power costs resulting from a Louisiana Supreme Court ruling (see Note 2). Fuel, fuel-related expenses and gas purchased for resale decreased in 1994 primarily due to lower gas prices.

Fuel for electric generation and fuel-related expenses increased in 1993 due primarily to a higher average per unit cost for gas resulting from increased gas prices in 1993 and increased generation, primarily at River Bend.

Other operation and maintenance expenses increased in 1994 due primarily to charges associated with certain contingencies as discussed in Note 13, additional Merger-related costs and restructuring costs as discussed in Note 12.

Other operation and maintenance expenses increased in 1993 due primarily to $52.3 million of Merger-related charges for financial investment advisor fees and early retirement and other severance plan provisions. Charges for other postemployment benefits increased resulting from the adoption of SFAS 106. Amortization of amounts in accordance with the River Bend phase-in plan also increased.

Income taxes decreased in 1994 due primarily to lower pretax income resulting from the charges discussed above.

Other

Other miscellaneous income decreased due to the write-off of plant held for future use in 1994 (see Note 13), establishment of a reserve related to the Cajun River Bend litigation (see Note 8), the write-off of previously disallowed rate deferrals, and obsolete spare parts, partially offset by lower interest expense as a result of the continued refinancing of high-cost debt.

Income taxes decreased in 1994 due primarily to the charges discussed above.

Other miscellaneous income decreased in 1993 due primarily to the 1992 effect of reducing a liability relating to a purchased power settlement. In accordance with the settlement, the liability was based upon the price of GSU common stock as of the November 1991 settlement and was subsequently reduced as the price of GSU common stock increased. Interest expense declined in 1993 as a result of the continued refinancing of high-cost debt.

Competition

The electric utility industry is becoming increasingly competitive and GSU is seeking to become a leading competitor in the changing electric energy business. Competition presents GSU with many challenges. The following have been identified by GSU as its major competitive challenges.

Retail and Wholesale Rate Issues

Increasing competition in the utility industry brings an increased need to stabilize or reduce retail rates. GSU implemented shared-savings plans as part of the Merger. Recognizing that many industrial customers have energy alternatives, GSU continues to work with these customers to address their needs. In certain cases, competitive prices are negotiated, using variable rate designs.

In connection with the Merger, GSU agreed with the LPSC and PUCT to a five-year Rate Cap on retail electric rates, and to pass through to retail customers the fuel savings and a certain percentage of the nonfuel savings created by the Merger. Under the terms of their respective Merger agreements, the LPSC and PUCT have reviewed GSU's base rates during the first post-Merger earnings analysis for reasonableness of its return on equity. The LPSC ordered a $12.7 million annual rate reduction effective January 1, 1995. GSU received an injunction delaying implementation of $8.3 million of the reduction and on January 1, 1995, reduced rates by $4.4 million. The entire $12.7 million is being appealed. On March 20, 1995, the PUCT ordered a $72.9 million annual base rate reduction for the period March 31, 1994, through September 1, 1994, decreasing to an annual base rate reduction of $52.9 million after September 1, 1994. In accordance with the Merger agreement, the rate reduction is applied retroactively to March 31, 1994. The rate reduction is being appealed and no assurance can be given as to the timing or outcome of the appeal. See Note 2 for further information.

See Note 2 for information on the settlement of several PUCT fuel cost reviews and the continuing likelihood of future reviews.

Retail wheeling, the transmission by an electric utility of energy produced by another entity over the utility's transmission and distribution system to a retail customer in the electric utility's service territory, is evolving. Over a dozen states have been studying the concept of retail competition. In April 1994, the state of Michigan agreed to a five-year experiment that allows limited competition among public utilities. During the same month, the California Public Utilities Commission proposed to deregulate that state's electric power industry, starting on January 1, 1996, to allow the largest industrial customers to select the lowest cost supplier for electricity service. Under the proposal, by the year 2002, smaller companies and residential customers in California would also be able to buy power from any suppliers. The California Public Utilities Commission is currently reviewing its decision and is expected to make a ruling in the first half of 1995. The retail market for electricity is expected to become more competitive with such moves toward deregulation.

In some areas of the country, municipalities (or comparable entities) whose residents are served at retail by an investor-owned utility pursuant to a franchise are exploring the possibility of establishing new or extending existing distribution systems or seeking new delivery points in order to serve retail customers, especially large industrial customers, that currently receive service from an investor-owned utility. These options depend on the terms of a utility's franchise as well as on state law and regulation. In addition, FERC's authority to order utilities

to transmit for a new or expanding municipal system is limited in certain respects. Where successful, however, the establishment of a municipal system or the acquisition by a municipal system of a utility's customers could result in the inability to recover costs that the utility has incurred in serving those customers.

In mid-1994, the FERC issued a notice of proposed rulemaking concerning a regulatory framework for dealing with recovery of stranded costs, such as high cost nuclear generating units, which may be incurred by electric utilities as a result of increased competition. In addition to addressing recovery of stranded costs related to wholesale service, the proposal requested comment as to recovery of retail stranded costs in transmission rates where state regulatory authorities failed to address the issue or were in conflict. Comments and reply comments have been filed, and the matter is pending. The risk of exposure to stranded costs which may result from competition in the industry will depend on the extent and timing of retail competition, the resolution of jurisdictional issues concerning stranded cost recovery, and the extent to which such costs are recovered from departing or remaining customers, among other matters.

Cogeneration projects developed or considered by certain of GSU's industrial customers over the last several years have resulted in GSU developing and securing approval of rates lower than the rates previously approved by the PUCT and LPSC for such industrial customers. Such rates are designed to retain such customers, and to compete for and develop new loads, and do not presently recover GSU's full cost of service. The pricing agreements at non-full cost of service based rates fully recover all related costs but provide only a minimal return. Substantially all of such pricing agreements expire no later than 1997. In 1994, KWH sales to GSU's industrial customers at non-full cost of service rates, which make up approximately 28% of the total industrial class, increased 13%. Sales to the remaining industrial customers increased 2%.

In the wholesale rate area, FERC approved in 1992, with certain modifications, the proposal of AP&L, LP&L, MP&L, NOPSI, and Entergy Power to sell wholesale power at market-based rates and to provide to electric utilities "open access" to the System's transmission system (subject to certain requirements). GSU was later added to this filing. On October 31, 1994, as amended on January 25, 1995, Entergy Services filed with FERC revised transmission tariffs intended to provide access to transmission service on the same or comparable basis, terms, and conditions as the Entergy operating companies, and the matter is pending. Open access and market pricing, once in effect, will increase marketing opportunities for GSU, but will also expose GSU to the risk of loss of load or reduced revenues due to competition with alternative suppliers.

In light of the rate issues discussed above, GSU is aggressively reducing costs to avoid potential earnings erosions that might result as well as to become more competitive. In 1994, GSU announced a restructuring program related to certain of its operating units. This program is designed to reduce costs and improve operating efficiencies. See Note 12 for further information. Also, in response to an increasingly competitive environment, GSU is continuing to work with the PUCT regarding integrated resource planning.

The Energy Policy Act of 1992

The EPAct addresses a wide range of energy issues and is altering the way Entergy and the rest of the electric utility industry operate. The EPAct encourages competition and affords utilities the opportunities, and the risks, associated with an open and more competitive market environment. The EPAct creates exemptions from regulation under the Holding Company Act and creates a class of exempt wholesale generators consisting of utility affiliates and nonutilities that are owners and operators of facilities for the generation and transmission of power for

sales at wholesale. The EPAct also gives FERC the authority to order investor-owned utilities, including GSU, to transmit power and energy to or for wholesale purchasers and sellers. The law creates the potential for electric utilities and other power producers to gain increased access to the transmission systems of other entities to facilitate wholesale sales. Both GSU and Entergy Power expect to compete in this market.

Litigation and Regulatory Proceedings

See Note 2 for information on the possible material adverse effects on GSU's financial condition and results of operations as a result of substantial write-offs and/or refunds in connection with outstanding appeals and remands regarding approximately $1.4 billion of abeyed company-wide River Bend plant costs and approximately $187 million ($170 million net of tax) of Texas retail jurisdiction deferred River Bend operating and carrying costs.

Entergy Corporation-GSU Merger

The acquisition of GSU by Entergy Corporation was the largest electric utility merger in United States history. Entergy expects to achieve $850 million in fuel cost savings and $670 million in operation and maintenance expense savings over ten years as a result of the Merger. For further information, see Note 2.

See Note 8 for information on the bankruptcy proceedings of Cajun and litigation with Cajun concerning Cajun's ownership interest in River Bend and the related possible material adverse effects on GSU's financial condition.

Deregulated Portion of River Bend

As of December 31, 1994, GSU had not recovered a significant amount of its investment in, or received any return associated with, the portion of River Bend included in the deregulated asset plan in Louisiana and the portion of River Bend placed in abeyance as part of the Texas rate order which went into effect in July 1988. See Note 2 for further information. Future earnings will continue to be limited as long as the limited recovery of the investment and lack of return continue.

For the year ended December 31, 1994, GSU recorded revenues resulting from the sale of electricity from the deregulated asset plan of approximately $34.1 million. Operation and maintenance expenses, including fuel, were approximately $30 million, and depreciation expense associated with the deregulated asset plan investment was approximately $16.7 million for the year ended December 31, 1994. For the year ended December 31, 1994, GSU recorded nonfuel revenue of $32.5 million (included in the $34.1 million of total deregulated asset plan revenue discussed above) which, absent the deregulated asset plan, would not have been realized. The operation and maintenance expenses and depreciation expense allocated to the deregulated asset plan as detailed above would have been incurred at River Bend with or without the deregulated asset plan. The future impact of the deregulated asset plan on GSU's results of operations and financial position will depend on River Bend's future operating costs, the unit's efficiency and availability, and the future market for energy over the remaining life of the unit. Based on current estimates of the factors discussed above, GSU anticipates that future revenues from the deregulated asset plan will fully recover all related costs.

Property Tax Exemptions

Exemption from the payment of property taxes on River Bend, which has been in effect for 10 years, will expire in December 1996. GSU is working with Louisiana local taxing authorities to determine the method for calculating the amount of the property taxes to be paid when the exemption expires. GSU believes that any property taxes allocated to its retail jurisdictions will be recovered from those customers in rates.

Environmental Issues

GSU has been notified by the U. S. Environmental Protection Agency (EPA) that it has been designated as a potentially responsible party for the cleanup of sites on which GSU and others have or have been alleged to have disposed of material designated as hazardous waste. GSU is currently negotiating with the EPA and state authorities regarding the cleanup of some of these sites. Several class action and other suits have been filed in state and federal courts seeking relief from GSU and others for damages caused by the disposal of hazardous waste and for asbestos-related disease allegedly resulting from exposure on GSU premises. While the amounts at issue in the cleanup efforts and suits may be substantial, GSU believes that its results of operations and financial condition will not be materially affected by the outcome of the suits. See Note 8 for further information.

Accounting Issues

Proposed Accounting Standards - The FASB has proposed a SFAS on "Accounting for the Impairment of Long-Lived Assets," effective January 1, 1996. The proposed standard describes circumstances which may result in assets being impaired and provides criteria for recognition and measurement of asset impairment. Note 2 describes regulatory assets of $170 million (net of tax) related to Texas retail deferred River Bend operating and carrying costs. Management believes these deferred costs will be required to be written off under the provisions of the new standard unless there are favorable regulatory or court actions related to these costs prior to the adoption of the new standard by GSU. Certain other operations of GSU are potentially affected by this standard, and any resulting write-offs will depend on future operating costs, generating units' efficiency and availability, and the future market for energy over the remaining life of the units. Based on current estimates, GSU anticipates that future revenues will fully recover the costs of such operations.

Continued Application of SFAS 71 - GSU's financial statements currently reflect, for the most part, assets and costs based on current cost-based ratemaking regulations, in accordance with SFAS 71, "Accounting for the Effects of Certain Types of Regulation." As discussed above, the electric utility industry is changing and these changes could possibly result in the discontinuance of the application of SFAS 71, which would result in the elimination of regulatory assets and liabilities. See Note 1 for further information.

Accounting for Decommissioning Costs - The FASB is currently reviewing the accounting for decommissioning of nuclear plants. This project could possibly change GSU's, as well as the entire utility industry's, accounting for such costs. For further information, see Note 8.

NOTE 1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

GSU maintains accounts in accordance with FERC and other regulatory guidelines. Certain previously reported amounts have been reclassified to conform to current classifications.

Revenues and Fuel Costs

Prior to January 1, 1993, GSU recognized electric and gas revenues when billed. To provide a better matching of revenues and expenses, effective January 1, 1993, GSU adopted a change in accounting principle to provide for accrual of the nonfuel portion of estimated unbilled revenues. The cumulative effect of this accounting change as of January 1, 1993 for the Texas retail jurisdiction, wholesale jurisdiction, and gas department increased 1993 net income by $10.7 million, net of related income taxes of $6.9 million. Had this new accounting method been in effect during prior years, net income before the cumulative effect would not have been materially different from that shown in the accompanying financial statements.

In the Louisiana retail jurisdiction, the LPSC issued a rate order, effective March 1, 1991, which required GSU to defer the initial effect when and if GSU changed its accounting for unbilled revenue. The amount of unbilled revenues in the Louisiana retail jurisdiction was $16.6 million at January 1, 1993. Because of the LPSC rate order, GSU recorded a deferred credit of $16.6 million. There was no cumulative effect of the change recorded in operations. If the LPSC order were to be revised, the net income effect would be $10.1 million, net of related income taxes of $6.5 million. Changes in unbilled revenues in the Louisiana retail jurisdiction subsequent to January 1, 1993 have been recorded in operations. See Note 2 regarding recent LPSC rate actions regarding the deferred unbilled revenues.

GSU's wholesale and Louisiana retail rate schedules include fuel adjustment clauses that allow deferral of fuel costs until such costs are reflected in the related revenues. Although deferred fuel accounting is also practiced in Texas, the Texas retail rate schedules include a fixed fuel factor approved by the PUCT, which remains in effect until changed as part of a general rate case, fuel reconciliation, or a fixed fuel factor filing. Reconcilable fuel and purchased power costs in excess of those included in base rates or recovered through fuel adjustment clauses are deferred (or accrued) until such costs are billed (or credited) to customers.

Utility Plant

Utility plant is stated at original cost. The original cost of utility plant retired or removed, plus the applicable removal costs, less salvage, is charged to accumulated depreciation. Maintenance, repairs, and minor replacement costs are charged to operating expenses. Substantially all of GSU's utility plant is subject to the lien of its mortgage indenture.

Total GSU net electric utility plant in service of $4.50 billion as of December 31, 1994 includes $3.22 billion of production plant, $.44 billion of transmission plant, $.69 billion of distribution plant and $.15 billion of other plant.

Depreciation is computed on the straight-line basis at rates based on the estimated service lives and cost of removal of the various classes of property. Depreciation provisions on average depreciable property approximated 2.7% in 1994, 1993, and 1992.

AFUDC represents the approximate net composite interest cost of borrowed funds and a reasonable return on the equity funds used for construction. Although AFUDC increases utility plant and increases earnings, it is only realized in cash through depreciation provisions included in rates. GSU's AFUDC rates were as follows:

January 1, 1992 - March 31, 1992	11.75%
April 1, 1992 - March 31, 1993	10.75%
April 1, 1993 - December 31, 1993	10.50%
1994 effective composite rate	10.20%

Jointly-Owned Facilities

GSU owns undivided interests in three jointly-owned electric generating stations and records the investment and expenses associated with these generating stations to the extent of its ownership interest. As of December 31, 1994, GSU's investment and accumulated depreciation in these generating stations were as follows:

Generating Stations	Fuel Type	Total Megawatt Capability	Ownership	Investment	Accumulated Depreciation
				(In Thousands)	
River Bend Unit 1	Nuclear	936	70%	$3,080,019	$617,002
Roy S. Nelson Unit 6	Coal	550	70%	$ 390,033	$145,897
Big Cajun 2, Unit 3	Coal	540	42%	$ 219,788	$ 74,442

See Note 8 for information regarding the current status of Cajun's 30% undivided ownership interest in River Bend.

Income Taxes

GSU, its parent, and affiliates file a consolidated federal income tax return. Income taxes are allocated to GSU in proportion to its contribution to the consolidated taxable income. SEC regulations require that no Entergy Corporation subsidiary pay more taxes than it would have had a separate income tax return been filed. Deferred taxes are recorded for all temporary differences between book and taxable income. Investment tax credits are deferred and amortized based upon the average useful life of the related property in accordance with rate treatment. As discussed in Note 3, in 1993 GSU changed its accounting for income taxes to conform with SFAS 109.

Inventories

GSU's fuel inventories (fuel oil and natural gas) are valued at weighted average cost.

Accounting for Power Plant Materials and Supplies

During the first quarter of 1992, accounting procedures were changed to include in inventory, power plant materials and supplies previously expensed or capitalized as plant in service. GSU believed this change provided a better matching of costs with related revenues. The change resulted from recommendations during audits by FERC and the LPSC, in addition to a general change in industry practice. The pro forma effect of retroactive application on any period prior to 1992 was not determinable as, prior to this change, GSU did not perform the physical inventory counts necessary to determine inventory balances in prior periods. The effect of the change was to increase materials and supplies by $76.6 million, of which $41.1 million associated with GSU's Texas and

Louisiana retail jurisdictions was deferred, and to decrease amounts previously capitalized, primarily plant in service, by $29 million. Amounts deferred for the Louisiana retail jurisdiction are currently being amortized to income over approximately seven years, through February 1998, while amounts deferred for the Texas retail jurisdiction are expected to be amortized to income in future years. The cumulative effect of this accounting change as of January 1, 1992, which relates to the operations on which GSU has discontinued regulatory accounting principles, amounted to $6.5 million before the related income tax effect of $2.5 million.

Reacquired Debt

The premiums and costs associated with reacquired debt are amortized over the life of the related new issuances for the portions of the business accounted for in accordance with generally accepted accounting principles for regulated enterprises.

During 1992, GSU extinguished over $1 billion of long-term debt through refinancings. A loss of $81.8 million was recorded associated with the extinguished debt of which $67.2 million of the loss was deferred, representing the portion of GSU's operations allocable to the Texas and Louisiana retail jurisdictions, and began to amortize that amount over the life of the new debt sold to retire the existing debt. A loss of $9.6 million, net of related income taxes of $5 million, was charged to income in 1992 as an extraordinary item. Further, refinancings of long-term debt during 1993 resulted in an extraordinary loss of $1.3 million, net of $.7 million of related taxes.

Cash and Cash Equivalents

GSU considers all unrestricted highly liquid debt instruments purchased with an original maturity of three months or less to be cash equivalents.

Continued Application of SFAS 71

As a result of the EPAct and actions of regulatory commissions, the electric utility industry is moving toward a combination of competition and a modified regulatory environment. GSU's financial statements, for the most part, currently reflect assets and costs based on current cost-based ratemaking regulations, in accordance with SFAS 71, "Accounting for the Effects of Certain Types of Regulation." Continued applicability of SFAS 71 to GSU's financial statements requires that rates set by an independent regulator on a cost of service basis (including a reasonable rate of return on invested capital) can actualiy be charged to and collected from customers.

In the event that either all or a portion of a utility's operations cease to meet those criteria for various reasons, including deregulation, a change in the method of regulation, or a change in the competitive environment for the utility's regulated services, the utility should discontinue application of SFAS 71 for the relevant portion. That discontinuation should be reported by elimination from the balance sheet of the effects of any actions of regulators recorded as regulatory assets and liabilities.

As of December 31, 1994, and for the foreseeable future, GSU's financial statements continue to follow SFAS 71, with the exceptions noted below.

SFAS 101

SFAS 101, "Regulated Enterprises - Accounting for the Discontinuation of Application of FASB Statement No. 71," specifies how an enterprise that ceases to meet the criteria for application of SFAS 71, to all or part of its operations should report that event in its financial statements. GSU discontinued regulatory accounting principles for its wholesale jurisdiction and steam department, and the Louisiana deregulated portion of River Bend, during 1989 and 1991, respectively.

Fair Value Disclosure

The estimated fair value of financial instruments has been determined by GSU using available market information and appropriate valuation methodologies. However, considerable judgment is required in developing the estimates of fair value. Therefore, estimates are not necessarily indicative of the amounts that GSU could realize in a current market exchange. In addition, gains or losses realized on financial instruments may be reflected in future rates and not accrue to the benefit of stockholders.

GSU considers the carrying amounts of financial instruments classified as current assets and liabilities to be a reasonable estimate of their fair value because of the short maturity of these instruments. See Notes 5, 6, and 8 for additional fair value disclosure.

The System adopted the provisions of SFAS 115, "Accounting for Certain Investments in Debt and Equity Securities," effective January 1, 1994. As a result, as of December 31, 1994, GSU recorded on the balance sheet an additional reduction of $0.9 million in decommissioning trust funds, representing the amount by which the fair value of the securities held in such funds exceeds the amounts recovered in rates for decommissioning and deposited in the funds and the related earnings on the amounts deposited. Due to the regulatory treatment for decommissioning trust funds, the System recorded an offsetting amount in unrealized losses on investment securities as a regulatory asset.

NOTE 2. RATE AND REGULATORY MATTERS

River Bend

In May 1988, the PUCT granted GSU a permanent increase in annual revenues of $59.9 million resulting from the inclusion in rate base of approximately $1.6 billion of company-wide River Bend plant investment and approximately $182 million of related Texas retail jurisdiction deferred River Bend costs (Allowed Deferrals). In addition, the PUCT disallowed as imprudent $63.5 million of company-wide River Bend plant costs and placed in abeyance, with no finding of prudence, approximately $1.4 billion of company-wide River Bend plant investment and approximately $157 million of Texas retail jurisdiction deferred River Bend operating and carrying costs. The PUCT affirmed that the ultimate rate treatment of such amounts would be subject to future demonstration of the prudence of such costs. GSU and intervening parties appealed this order (Rate Appeal) and GSU filed a separate rate case asking that the abeyed River Bend plant costs be found prudent (Separate Rate Case). Intervening parties filed suit in a Texas district court to prohibit the Separate Rate Case. The district court's decision was ultimately appealed to the Texas Supreme Court, which ruled in 1990 that the prudence of the purported abeyed costs could not be relitigated in a separate rate proceeding. The Texas Supreme Court's decision stated that all issues relating to the merits of the original PUCT order, including the prudence of all River Bend-related costs, should be addressed in the Rate Appeal.

In October 1991, the Texas district court in the Rate Appeal issued an order holding that, while it was clear the PUCT made an error in assuming it could set aside $1.4 billion of the total costs of River Bend and consider them in a later proceeding, the PUCT, nevertheless, found that GSU had not met its burden of proof related to the amounts placed in abeyance. The court also ruled that the Allowed Deferrals should not be included in rate base. The court further stated that the PUCT had erred in reducing GSU's deferred costs by $1.50 for each $1.00 of revenue collected under the interim rate increases authorized in 1987 and 1988. The court remanded the case to the PUCT with instructions as to the proper handling of the Allowed Deferrals. GSU's motion for rehearing was denied and, in December 1991, GSU filed an appeal of the October 1991 district court order. The PUCT also appealed the October 1991 district court order, which served to supersede the district court's judgment, rendering it unenforceable under Texas law.

In August 1994, the Texas Third District Court of Appeals (the Appellate Court) affirmed the district court's decision that there was substantial evidence to support the PUCT's 1988 decision not to include the abeyed construction costs in GSU's rate base. While acknowledging that the PUCT had exceeded its authority when it attempted to defer a decision on the inclusion of those costs in rate base in order to allow GSU a further opportunity to demonstrate the prudence of those costs in a subsequent proceeding, the Appellate Court found that GSU had suffered no harm or lack of due process as a result of the PUCT's error. Accordingly, the Appellate Court held that the PUCT's action had the effect of disallowing the company-wide $1.4 billion of River Bend construction costs for ratemaking purposes. In its August 1994 opinion, the Appellate Court also held that GSU's deferred operating and maintenance costs associated with the allowed portion of River Bend should be included in rate base and that GSU's deferred River Bend carrying costs included in the Allowed Deferrals should also be included in rate base. The Appellate Court's August 1994 opinion affirmed the PUCT's original order in this case.

The Appellate Court's August 1994 opinion was entered by two judges, with a third judge dissenting. The dissenting opinion states that the result of the majority opinion is, among other things, to deprive GSU of due process at the PUCT because the PUCT never reached a finding on the $1.4 billion of construction costs.

In October 1994, the Appellate Court denied GSU's motion for rehearing on the August 1994 opinion as to the $1.4 billion in River Bend construction costs and other matters. GSU appealed the Appellate Court's decision to the Texas Supreme Court, where it is pending.

As of December 31, 1994, the River Bend plant costs disallowed for retail ratemaking purposes in Texas, the River Bend plant costs held in abeyance, and the related operating and carrying cost deferrals totaled (net of taxes) approximately $13 million, $280 million (both net of depreciation), and $170 million, respectively. Allowed Deferrals were approximately $107 million, net of taxes and amortization, as of December 31, 1994. GSU estimates it has collected approximately $158 million of revenues as of December 31, 1994, as a result of the originally ordered rate treatment by the PUCT of these deferred costs. If recovery of the Allowed Deferrals is not upheld, future revenues based upon those allowed deferrals could also be lost, and no assurance can be given as to whether or not refunds of revenue received based upon such deferred costs previously recorded will be required.

No assurance can be given as to the timing or outcome of the remands or appeals described above. Pending further developments in these cases, GSU has made no write-offs or reserves for the River Bend-related costs. Management believes, based on advice from Clark, Thomas & Winters, a Professional Corporation, legal counsel of record in the Rate Appeal, that it is reasonably possible that the case will be remanded to the PUCT, and the PUCT will be allowed to rule on the prudence of the abeyed River Bend plant costs. Rate Caps imposed by the PUCT's regulatory approval of the Merger could result in GSU being unable to use the full amount of a favorable decision to immediately increase rates; however, a favorable decision could permit some increases and/or limit or

prevent decreases during the period the Rate Caps are in effect. At this time, management and legal counsel are unable to predict the amount, if any, of the abeyed and previously disallowed River Bend plant costs that ultimately may be disallowed by the PUCT. A net of tax write-off as of December 31, 1994, of up to $293 million could be required based on an ultimate adverse ruling by the PUCT on the abeyed and disallowed costs.

In prior proceedings, the PUCT has held that the original cost of nuclear power plants will be included in rates to the extent those costs were prudently incurred. Based upon the PUCT's prior decisions, management believes that its River Bend construction costs were prudently incurred and that it is reasonably possible that it will recover in rate base, or otherwise through means such as a deregulated asset plan, all or substantially all of the abeyed River Bend plant costs. However, management also recognizes that it is reasonably possible that not all of the abeyed River Bend plant costs may ultimately be recovered.

As part of its direct case in the Separate Rate Case, GSU filed a cost reconciliation study prepared by Sandlin Associates, management consultants with expertise in the cost analysis of nuclear power plants, which supports the reasonableness of the River Bend costs held in abeyance by the PUCT. This reconciliation study determined that approximately 82% of the River Bend cost increase above the amount included by the PUCT in rate base was a result of changes in federal nuclear safety requirements and provided other support for the remainder of the abeyed amounts.

There have been four other rate proceedings in Texas involving nuclear power plants. Investment in the plants ultimately disallowed ranged from 0% to 15%. Each case was unique, and the disallowances in each were made on a case-by-case basis for different reasons. Appeals of two of these PUCT decisions are currently pending.

The following factors support management's position that a loss contingency requiring accrual has not occurred, and its belief that all, or substantially all, of the abeyed plant costs will ultimately be recovered:

1. The $1.4 billion of abeyed River Bend plant costs have never been ruled imprudent and disallowed by the PUCT.
2. Sandlin Associates' analysis which supports the prudence of substantially all of the abeyed construction costs.
3. Historical inclusion by the PUCT of prudent construction costs in rate base.
4. The analysis of GSU's internal legal staff, which has considerable experience in Texas rate case litigation.

Additionally, management believes, based on advice from Clark, Thomas & Winters, a Professional Corporation, legal counsel of record in the Rate Appeal, that it is reasonably possible that the Allowed Deferrals will continue to be recovered in rates. Management also believes, based on advice from Clark, Thomas & Winters, a Professional Corporation, legal counsel of record in the Rate Appeal, that it is reasonably possible that the deferred costs related to the $1.4 billion of abeyed River Bend plant costs will be recovered in rates to the extent that the $1.4 billion of abeyed River Bend plant is recovered. However, a net of tax write-off of the $170 million of deferred costs related to the $1.4 billion of abeyed River Bend plant costs would be required if they are not allowed to be recovered in rates.

A proposed accounting standard, "Accounting for the Impairment of Long-Lived Assets," which is expected to become effective January 1, 1996, may require the write-off of the $170 million of rate deferrals discussed above, upon adoption of the standard unless there are favorable regulatory or court actions related to these costs prior to adoption.

Merger-Related Rate Agreements

In November 1993, Entergy Corporation, AP&L, MP&L, and NOPSI entered into separate settlement agreements whereby the APSC, MPSC, and Council agreed to withdraw from the SEC proceeding related to the Merger. In return AP&L, MP&L, and NOPSI agreed, among other things, that their retail ratepayers would be protected from (1) increases in the cost of capital resulting from risks associated with the Merger, (2) recovery of any portion of the acquisition premium or transactional costs associated with the Merger, (3) certain direct allocations of costs associated with GSU's River Bend nuclear unit, and (4) any losses of GSU resulting from resolution of litigation in connection with its ownership of River Bend.

The LPSC and the PUCT approved separate regulatory proposals that include the following elements: (1) a five-year Rate Cap on GSU's retail electric base rates in the respective states, except for force majeure (defined to include, among other things, war, natural catastrophes, and high inflation); (2) a provision for passing through to retail customers in the respective states the jurisdictional portion of the fuel savings created by the Merger; and (3) a mechanism for tracking nonfuel operation and maintenance savings created by the Merger. The LPSC regulatory plan provides that such nonfuel savings will be shared 60% by the shareholder and 40% by ratepayers during the eight years following the Merger. The LPSC plan requires regulatory filings each year by the end of May through 2001. The PUCT regulatory plan provides that such savings will be shared equally by the shareholder and ratepayers, except that the shareholder's portion will be reduced by $2.6 million per year on a total company basis in years four through eight. The PUCT plan also requires a series of future regulatory filings in November 1996, 1998, and 2001, to ensure that ratepayers' share of such savings be reflected in rates on a timely basis and requires Entergy Corporation to hold GSU's Texas retail customers harmless from the effects of the removal by FERC of a 40% cap on the amount of fuel savings GSU may be required to transfer to other System operating companies under the FERC tracking mechanism (see below). On January 14, 1994, Entergy Corporation filed a request for rehearing of FERC's December 15, 1993, order approving the Merger requesting that FERC restore the 40% cap provision in the fuel cost protection mechanism. The matter is pending.

FERC approved certain rate schedule changes to integrate GSU into the System Agreement. Certain commitments were adopted to provide reasonable assurance that the ratepayers of AP&L, LP&L, MP&L, and NOPSI will not be allocated higher costs, including, among other things, (1) a tracking mechanism to protect AP&L, LP&L, MP&L, and NOPSI from certain unexpected increases in fuel costs, (2) the distribution of profits from power sales contracts entered into prior to the Merger, (3) a methodology to estimate the cost of capital in future FERC proceedings, and (4) a stipulation that AP&L, LP&L, MP&L, and NOPSI will be insulated from certain direct effects on capacity equalization payments should GSU acquire Cajun's 30% share in River Bend (see Note 8).

Filings with the PUCT and Texas Cities

In March 1994, the Texas Office of Public Utility Counsel and certain cities served by GSU instituted an investigation of the reasonableness of GSU's rates. In June 1994, GSU provided the cities with information that GSU believed supported the current rate level. GSU filed the same information with the PUCT in June 1994, pursuant to provisions of the Merger. In September 1994, the various cities adopted ordinances directing GSU to reduce its Texas retail rates by $45.9 million. GSU appealed the cities' ordinances to the PUCT for a determination of reasonableness of GSU's rates.

In November 1994, those cities that intervened in the PUCT appeal filed testimony with the PUCT supporting a $118 million base rate reduction in lieu of the previously proposed $45.9 million reduction. In November 1994, the PUCT staff filed testimony that supported a $38.2 million base rate reduction. GSU filed

information with the PUCT that it believed supported the current level of rates. Hearings were held in December 1994 and on March 20, 1995, the PUCT ordered a $72.9 million annual base rate reduction for the period March 31, 1994, through September 1, 1994, decreasing to an annual base rate reduction of $52.9 million after September 1, 1994. In accordance with the Merger agreement, the rate reduction is applied retroactively to March 31, 1994. As a result, GSU recorded in 1994 a $57 million reserve for rate refund and a $12.8 million reserve for franchise taxes to be refunded. These charges reduced net income after tax by $41.6 million. The rate reduction is being appealed and no assurance can be given as to the timing or outcome of the appeal.

Texas Cities Rate Settlement - 1993

In June 1993, 13 cities within GSU's Texas service area instituted an investigation to determine whether GSU's current rates were justified. In October 1993, the general counsel of the PUCT instituted an inquiry into the reasonableness of GSU's rates. In November 1993, a settlement agreement was filed with the PUCT which provided for an initial reduction in GSU's annual retail base revenues in Texas of approximately $22.5 million effective for electric usage on or after November 1, 1993, and a second reduction of $20 million effective September 1994. Pursuant to the settlement, GSU reduced rates with a $20 million one-time bill credit in December 1993, and refunded approximately $3 million to Texas retail customers on bills rendered in December 1993. The PUCT approved the settlement agreement on July 21, 1994. The cities' rate inquiries were settled earlier on the same terms.

LPSC Rate Order - 1994

In May 1994, GSU made the required first post-Merger earnings analysis filing with the LPSC. On December 14, 1994, the LPSC ordered a $12.7 million annual rate reduction for GSU effective January 1995. The rate order included, among other things, a reduction in GSU's Louisiana jurisdictional authorized return on equity from 12.75% to 10.95% and the amortization for the benefit of the customers of $8.3 million of previously deferred unbilled revenue, representing one-half of the total resulting from a change in accounting discussed in Note 1. On December 28, 1994, GSU received a preliminary injunction from the 19th Judicial District Court regarding $8.3 million of the reduction. On January 1, 1995, GSU reduced rates by $4.4 million. The entire $12.7 million reduction is being appealed and no assurance can be given as to the timing or outcome of the appeal.

PUCT Fuel Cost Review (December 1, 1986 - September 30, 1991)

In January 1992, GSU applied to the PUCT for a new fixed fuel factor and requested a final reconciliation of fuel and purchased power costs incurred between December 1, 1986 and September 30, 1991. GSU proposed to recover net underrecoveries and interest (including underrecoveries related to Nelson Industrial Steam Company (NISCO), discussed below) over a twelve-month period.

In April 1993, the presiding PUCT administrative law judge (ALJ) issued a report concluding that GSU incurred approximately $117 million of nonreimbursable fuel costs on a company-wide basis (approximately $50 million on a Texas retail jurisdictional basis) during the reconciliation period. Included in the nonreimbursable fuel costs were payments above GSU's avoided cost rate for power purchased from NISCO. The PUCT ordered in 1986 that the purchased power costs from NISCO in excess of GSU's avoided costs be disallowed. The PUCT disallowance resulted in approximately $12 million to $15 million of unrecovered purchased power costs on an annual basis, which GSU continued to expense as the costs were incurred. In April 1991, the Texas Supreme Court, in the appeal of such order, ordered the PUCT to allow GSU to recover purchased power payments in excess of its avoided cost in future proceedings, if GSU established to the PUCT's satisfaction that the payments were reasonable and necessary expenses.

In June 1993, the PUCT concluded that the purchased power payments made to NISCO in excess of GSU's avoided cost were not reasonably incurred. As a result of the order, GSU recorded additional fuel expenses (including interest) of $2.8 million for non-NISCO related items. The PUCT's order resulted in no additional expenses related to the NISCO issue, or for overcollections related to the fixed fuel factor, as those charges were expensed by GSU as they were incurred. The PUCT concluded that GSU had over-collected its fuel costs in Texas and ordered GSU to refund approximately $33.8 million to its Texas retail customers, including approximately $7.5 million of interest. In that proceeding, the PUCT also set GSU's fixed fuel factor in Texas at 1.84 cents per KWH in response to GSU's request that the factor be set at 2.02 cents per KWH. In October 1993, GSU appealed the PUCT's order to the Travis County District Court where the matter is still pending. No assurance can be given as to the timing or outcome of that appeal. In a subsequent proceeding to review GSU's fuel factor, the PUCT approved GSU's request to further reduce its fixed fuel factor in Texas to 1.78 cents per KWH from 1.84 cents per KWH.

PUCT Fuel Cost Review (October 1, 1991 - December 31, 1993)

On January 9, 1995, GSU and various parties reached an agreement for the reconciliation of over- and under-recovery of fuel and purchased power expenses for the period October 1, 1991, through December 31, 1993. While the settlement still requires PUCT approval, GSU believes it will ultimately be approved and has accordingly recorded a reserve of $7.6 million.

LPSC Fuel Cost Review

In November 1993, the LPSC ordered a review of GSU's fuel costs for the period October 1988 through September 1991 (Phase I) based on the number of outages at River Bend and the findings in the June 1993 PUCT fuel reconciliation case. In July 1994, the LPSC ruled in the Phase I fuel review case and ordered GSU to refund approximately $27 million to its customers. Under the order, a refund of $13.1 million, which was not contested under a Louisiana Supreme Court decision as discussed below, was made through a billing credit on August 1994 bills. In August 1994, GSU appealed the remaining portion of the LPSC ordered refund to the district court. GSU has made no reserve for the remaining portion, pending outcome of the district court appeal, and no assurance can be given as to the timing or outcome of the appeal.

On January 18, 1995, GSU met with the Special Counsel of the LPSC to discuss the procedural schedule for the upcoming fuel review (Phase II). The period under investigation was determined to be from October 1991 to December 1994. Hearings are scheduled to begin in July 1995.

In February 1990, the LPSC disallowed the pass-through to ratepayers for the portion of GSU's cost to purchase power from NISCO representing the excess of NISCO's purchase price of the units over GSU's depreciated cost of the units. GSU appealed the 1990 order. In March 1994, the Louisiana Supreme Court ruled in favor of the LPSC. GSU recorded an estimated refund provision of $13.1 million, before related income taxes of $5.3 million.

Deregulated Asset Plan

A deregulated asset plan representing an unregulated portion (approximately 22%) of River Bend (plant costs, generation, revenues, and expenses) was established pursuant to a January 1992 LPSC order. The plan allows GSU to sell such generation to Louisiana retail customers at 4.6 cents per KWH or off-system at higher prices with certain sharing provisions for such incremental revenue.

River Bend Cost Deferrals

GSU deferred approximately $369 million of River Bend operating costs, purchased power costs, and accrued carrying charges pursuant to a 1986 PUCT accounting order. Approximately $182 million of these costs are being amortized over a 20-year period, and the remaining $187 million are not being amortized pending the ultimate outcome of the Rate Appeal. As of December 31, 1994, the unamortized balance of these costs was $321 million. Further, GSU deferred approximately $400.4 million of similar costs pursuant to a 1986 LPSC accounting order. These costs, of which approximately $122 million are unamortized as of December 31, 1994, are being amortized over a 10-year period ending in 1997.

In accordance with a phase-in plan approved by the LPSC, GSU deferred $294 million of its River Bend costs related to the period February 1988 through February 1991. GSU has amortized $129 million through December 31, 1994, and the remainder of $165 million will be recovered over approximately 3.2 years.

NOTE 3. INCOME TAXES

(1) Income tax expense (benefit) consisted of the following:

	For the Years Ended December 31,		
	1994	1993	1992
	(In Thousands)		
Current			
Federal	$ 71	$ 16,714	$ 5,621
State	14	-	-
Total	85	16,714	5,621
Deferred - net			
Liberalized depreciation	21,560	37,951	24,287
Nuclear unit cancellation costs, net of amortization	(2,111)	(2,930)	(3,107)
Fuel and purchased power costs (accrued)	8,266	7,689	(669)
Expenses deferred for tax purposes	(33,358)	(12,387)	3,449
Tax net operating loss carryforward	56,736	(8,357)	12,349
Rate deferrals - net	(37,477)	(24,458)	(21,238)
Unbilled revenues	(2,093)	4,999	2,889
Income deferred for book purposes	(1,845)	(2,102)	2,328
Louisiana provision for rate refund	-	3,793	4,416
Texas provision for rate refund	(23,034)	-	-
Alternative minimum tax	118	(22,183)	(8,197)
Loss on debt extinguishment, net of amortization	(2,215)	1,398	22,314
Purchased power settlement	-	66,753	6,562
Write-off of plant held for future use	(29,572)	-	-
Other	(12,886)	(3,689)	4,590
Total	(57,911)	46,477	49,973
Investment tax credit adjustments - net	(4,260)	1,093	(2,200)
Recorded income tax expense	$(62,086)	$ 64,284	$ 53,394
Charged to operations	$ (6,448)	$ 46,007	$ 38,058
Charged to other income	(55,638)	12,009	17,801
Charged to extraordinary items	-	(671)	(4,943)
Charged to cumulative effect of accounting changes	-	6,939	2,478
Total income taxes	$(62,086)	$ 64,284	$ 53,394

Income taxes differ from the amounts computed by applying the statutory federal income tax rate to income before taxes. The reasons for these differences were:

	For the Years Ended December 31,					
	1994		1993		1992 (1)	
	Amount	% of Pretax Income	Amount	% of Pretax Income	Amount	% of Pretax Income
	(Dollars in Thousands)					
Computed at statutory rate	$(50,694)	(35.0)	$ 50,101	35.0	$63,662	34.0
Increases (reductions) in tax resulting from:						
State income taxes net of federal income tax effect	(6,571)	(4.5)	1,332	0.9	3,573	1.9
Rate deferrals - net	6,551	4.5	6,193	4.3	5,439	2.9
Depreciation	(8,188)	(5.7)	(11,343)	(7.9)	(15,479)	(8.3)
Impact of change in tax rate	-	-	5,179	3.6	-	-
Book expenses not deducted for tax	151	0.1	15,134	10.6	142	0.1
Amortization of investment tax credits	(4,472)	(3.1)	(4,435)	(3.1)	(4,356)	(2.3)
Other - net	1,137	0.8	2,123	1.5	413	0.2
Total income taxes	$(62,086)	(42.9)	$ 64,284	44.9	$53,394	28.5

Significant components of net deferred tax liabilities, as of December 31, 1994 and 1993, were (in thousands):

	1994	1993
Deferred tax liabilities:		
Net regulatory assets	$ (494,443)	$ (529,706)
Plant related basis differences	(1,065,053)	(1,023,446)
Rate deferrals - net	(132,213)	(169,689)
Debt reacquisition loss	(21,922)	(24,140)
Other	(1,241)	(25,871)
Total	$(1,714,872)	$(1,772,852)
Deferred tax assets:		
Net operating loss carryforwards	$ 251,000	$ 307,737
Investment tax credit carryforward	173,852	176,032
Valuation allowance-investment tax credit carryforward	(64,407)	(15,213)
Unbilled revenue	14,336	12,243
Plant related basis differences	23,796	25,007
Alternative minimum tax credit	39,743	39,860
Texas provision for rate refund	23,034	-
Other	202,579	164,135
Total	$ 663,933	$ 709,801
Net deferred tax liability	$(1,050,939)	$(1,063,051)

As of December 31, 1994, for tax purposes, GSU had federal tax loss carryforwards of approximately $666.7 million, state tax loss carryforward of approximately $498.2 million, and investment tax (ITC) and other credit carryforwards of approximately $176.4 million which will be used to reduce income tax payments in future years and, if not used, will expire through the year 2008. It is currently anticipated that approximately $64.4 million of ITC carryforwards will expire unutilized as a result of limitations arising from the Merger. A valuation allowance has been provided for deferred tax assets relating to that amount. The alternative minimum tax credit, which can be carried forward indefinitely to reduce GSU's future federal income tax liability, was $40.6 million as of December 31, 1994.

In 1993, GSU adopted SFAS 109. SFAS 109 required that deferred income taxes be recorded for all temporary differences and carryforwards, and that deferred tax balances be based on enacted tax laws at tax rates that are expected to be in effect when the temporary differences reverse. SFAS 109 required that regulated enterprises recognize adjustments resulting from its implementation as regulatory assets or liabilities if it is probable that such amounts will be recovered from or returned to customers in future rates. A substantial majority of the adjustments required by SFAS 109 were recorded to deferred tax balance sheet accounts with offsetting adjustments to regulatory assets and liabilities. GSU recorded the adoption of SFAS 109 by restating 1990, 1991, and 1992 financial statements and including a charge of $96.5 million for the cumulative effect of the adoption of SFAS 109 in 1990 primarily for that portion of the operations on which GSU has discontinued regulatory accounting principles.

NOTE 4. LINES OF CREDIT AND RELATED BORROWINGS

The SEC has authorized GSU to effect short-term borrowings up to $125 million, which may be increased to as much as $395 million after further SEC approval. This authorization is effective through November 30, 1996. As of December 31, 1994, GSU had unused lines of credit for short-term borrowings of $5 million. Interest rates associated with these lines of credit generally are based on the prime rate, the EURO dollar rate, or a certificate of deposit rate. Commitment fees on these lines of credit are .125% of the amount of available credit. In addition, GSU can borrow from the Money Pool, subject to its maximum authorized level of short-term borrowings and the availability of funds. GSU had no outstanding borrowings under the Money Pool arrangement as of December 31, 1994.

NOTE 5. PREFERRED, PREFERENCE, AND COMMON STOCK

The number of shares and dollar value of GSU's preferred and preference stock were:

	As of December 31				Call Price Per Share as of December 31, 1994
	Shares Outstanding		Total Dollar Value		
	1994	1993	1994	1993	
			(Dollars in Thousands)		
Preference Stock					
Authorized 20,000,000 shares, without par value, cumulative					
7% Series (2)	6,000,000	6,000,000	$ 150,000	$ 150,000	(1)
Preferred Stock					
Authorized 6,000,000 shares, $100 par value, cumulative					
Without sinking fund:					
4.40% Series	51,173	51,173	$ 5,117	$ 5,117	$108.00
4.50% Series	5,830	5,830	583	583	$105.00
4.40% - 1949 Series	1,655	1,655	166	166	$103.00
4.20% Series	9,745	9,745	975	975	$102.82
4.44% Series	14,804	14,804	1,480	1,480	$103.75
5.00% Series	10,993	10,993	1,099	1,099	$104.25
5.08% Series	26,845	26,845	2,685	2,685	$104.63
4.52% Series	10,564	10,564	1,056	1,056	$103.57
6.08% Series	32,829	32,829	3,283	3,283	$103.34
7.56% Series	350,000	350,000	35,000	35,000	$101.80
8.52% Series	500,000	500,000	50,000	50,000	$102.43
9.96% Series	350,000	350,000	35,000	35,000	$102.64
Total without sinking fund	1,364,438	1,364,438	$ 136,444	$136,444	
With sinking fund:					
8.80% Series	226,807	237,963	$ 22,680	$ 23,796	$100.00
9.75% Series	21,565	22,576	2,154	2,258	$100.00
8.64% Series	182,000	196,000	18,200	19,600	$101.00
Adjustable Rate Series A, 7.10% (3)	204,000	216,000	20,400	21,600	$100.00
Adjustable Rate Series B, 7.15% (3)	315,000	337,500	31,500	33,750	$100.00
Total with sinking fund	949,372	1,010,039	$ 94,934	$101,004	

(1) This series is not redeemable as of December 31, 1994.
(2) The total dollar value represents the involuntary liquidation value of $25 per share.
(3) Rates are as of December 31, 1994.

The fair value of GSU's preferred and preference stock with sinking fund was estimated to be approximately $227.8 million and $255 million as of December 31, 1994 and 1993, respectively. The fair values were determined using quoted market prices or estimates from nationally recognized investment banking firms. See Note 1 for additional information on disclosure of fair value of financial instruments.

Changes in the common stock, preference stock, and preferred stock during the last three years were:

	Number of Shares		
	1994	1993	1992
Common stock issuances	-	100	-
Common stock retirements with Merger closing	-	(114,055,065)	-
Preference stock issuances	-	6,000,000	-
Preference stock retirements	-	-	(4,000,000)
Preferred stock with sinking fund retirements	(60,667)	(1,683,834)	(559,257)

Minimum cash sinking fund requirements for preferred stock with sinking funds are $6.1 million for each of the years 1995-1999. Limitations based on the ratio of after-tax earnings to fixed charges and preferred dividends are imposed by GSU's Restated Articles of Incorporation (Articles) upon the issuance of additional preferred stock. Based upon the results of operations for the year ended December 31, 1994, GSU is unable to issue any additional preferred stock.

NOTE 6. LONG-TERM DEBT

GSU's long-term debt as of December 31, 1994 and 1993, was as follows:

Maturities		Interest Rates		December 31	
From	To	From	To	1994	1993
				(In Thousands)	
First Mortgage Bonds					
1996	1999	5%	7.35%	$ 445,000	$ 345,000
2000	2004	6.41%	8-1/2%	670,000	470,000
2005	2009	6.77%	8-7/8%	120,000	420,000
2023	2024	8.70%	8.94%	450,000	450,000
Governmental and Industrial Development Bonds					
2006	2024	5.9%	12%	482,460	482,885
Debentures - Due 1998, 6.72%				200,000	200,000
Other long-term debt				6,879	6,879
Unamortized premium and discount - net				(5,497)	(5,700)
Total long-term debt				2,368,842	2,369,064
Less amount due within one year				50,425	425
Long-term debt excluding amount due within one year				$2,318,417	$2,368,639

The fair value of GSU's long-term debt as of December 31, 1994 and 1993 was estimated to be $2,277.3 million and $2,548.1 million, respectively. Fair values were determined using bid prices reported by dealer markets and by nationally recognized investment banking firms. See Note 1 for additional information on disclosure of fair value of financial instruments.

For the years 1995, 1996, 1997, 1998, and 1999, GSU has long-term debt maturities and cash sinking fund requirements of (in millions) $50.4, $145.4, $160.9, $190.9 and $100.9, respectively. In addition, other sinking

fund requirements for the years 1995, 1996, 1997, 1998, and 1999 of (in millions) $16.7, $16.5, $15.2, $13.5, and $12.3, respectively, may be satisfied by cash or by certification of property additions at a rate of 167% of such requirements.

GSU has two outstanding series of pollution control bonds which are collateralized by irrevocable letters of credit which are scheduled to expire before the scheduled maturity of the bonds. The letter of credit collateralizing the $28.4 million variable rate series due December 1, 2015, expires in September 1996 and the letter of credit collateralizing the $20 million variable rate series due April 1, 2016, expires in April 1996. GSU plans to refinance these series or renew the letters of credit.

NOTE 7. DIVIDEND RESTRICTIONS

Certain limitations on the payment of cash dividends on common stock are contained in the Articles, Mortgage Indenture, and applicable state and federal law. As of December 31, 1994, none of GSU's retained earnings were restricted against the payment of cash dividends or other distributions on common stock.

NOTE 8. COMMITMENTS AND CONTINGENCIES

Financial Condition

Although GSU received partial rate relief relating to River Bend, GSU's financial position was strained from 1986 to 1990 by its inability to earn a return on and fully recover its investment and other costs associated with River Bend. Issues to be finally resolved in PUCT rate proceedings and appeals thereof, as discussed in Note 2, combined with certain significant business relationships (discussed below) and the application of accounting standards, may result in substantial write-offs and charges that could result in substantial net losses being reported in 1995, and subsequent periods, with resulting substantial adverse adjustments to common shareholder's equity. Future earnings will continue to be adversely affected by the lack of full recovery and return on the investment and other costs associated with River Bend.

Cajun - River Bend

GSU has significant business relationships with Cajun, including co-ownership of River Bend and Big Cajun 2, Unit 3. GSU and Cajun own 70% and 30% undivided interests in River Bend, respectively, and 42% and 58% undivided interests in Big Cajun 2, Unit 3, respectively.

In June 1989, Cajun filed a civil action against GSU in the United States District Court for the Middle District of Louisiana (District Court). Cajun's complaint seeks to annul, rescind, terminate, and/or dissolve the Joint Ownership Participation and Operating Agreement entered into on August 28, 1979 (Operating Agreement) relating to River Bend. Cajun alleges fraud and error by GSU, breach of its fiduciary duties owed to Cajun, and/or GSU's repudiation, renunciation, abandonment, or dissolution of its core obligations under the Operating Agreement, as well as the lack or failure of cause and/or consideration for Cajun's performance under the Operating Agreement. The suit seeks also to recover Cajun's alleged $1.6 billion investment in the unit as damages, plus attorneys' fees, interest, and costs. Two member cooperatives of Cajun have brought an independent action to declare the Operating Agreement void, based upon failure to get prior LPSC approval alleged to be necessary. GSU believes the suits are without merit and is contesting them vigorously.

A trial without jury on the portion of the suit by Cajun to rescind the Operating Agreement which began in April 1994 has been completed, and an order from the District Court is pending. No assurance can be given as to the outcome of this litigation. If GSU were ultimately unsuccessful in this litigation and were required to make substantial payments, GSU would probably be unable to make such payments and would probably have to seek relief from its creditors under the United States Bankruptcy Code. If GSU prevails in this litigation, there can be no assurance that the Bankruptcy Court will allow funding of all required costs of Cajun's ownership in River Bend.

Since 1992 Cajun has not paid its full share of operating and maintenance expenses and other costs for repairs and improvements to River Bend. In addition, certain costs and expenses paid by Cajun were paid under protest. These actions were taken by Cajun based on its contention, which GSU disagrees, that River Bend's operating and maintenance expenses were excessive.

In a letter dated October 21, 1994, and at a subsequent meeting, Cajun representatives advised Entergy Corporation and GSU that, on October 25, 1994, Cajun would exhaust its 1994 budget for operating and maintenance expenses for River Bend, and did not make any further payments to GSU in 1994 for River Bend operating, maintenance or capital costs. Cajun also advised that the RUS (which provided funding to Cajun for its investment in River Bend) would not permit Cajun to budget funds in 1995 to pay its share of operating and maintenance expenses or capital costs for River Bend. However, Cajun stated that it would continue to fund its share of the nuclear decommissioning trust payments for River Bend, as well as insurance and safety-related expenses. The unpaid portion of Cajun's River Bend operating, maintenance, and capital costs for 1994 (which has been fully reserved) was approximately $22.4 million. Cajun's total share of River Bend annual operating (including nuclear fuel) and maintenance expenses and capital costs was approximately $76.1 million in 1994.

In view of Cajun's stated expectation that it will fund only a limited portion of its share of River Bend related operating, maintenance, and capital costs, GSU notified Cajun that it would (i) credit GSU's share of expenses for Big Cajun 2, Unit 3 against amounts due from Cajun to GSU and (ii) seek to market Cajun's share of the power from River Bend and apply the proceeds to the amounts due from Cajun to GSU. On November 2, 1994, Cajun discontinued GSU's entitlement of energy from Big Cajun 2, Unit 3. In response, on November 3, 1994, GSU filed pleadings in District Court seeking an order requiring Cajun to provide GSU with the energy from Big Cajun 2, Unit 3 to which GSU is entitled, and holding that GSU is entitled to credit amounts due from GSU to Cajun for Big Cajun 2, Unit 3 against amounts due from Cajun to GSU with respect to River Bend. On December 19, 1994, the District Court issued an injunction prohibiting Cajun from denying its share of energy from Big Cajun 2, Unit 3 and stipulating that GSU must make payments for its portion of expenses for Big Cajun 2, Unit 3 to the registry of the District Court.

On December 14, 1994, the LPSC ordered Cajun to decrease the rates charged to its member distribution cooperatives by approximately $30 million per year. The rate decrease is associated with the LPSC's prior finding of imprudence in Cajun's participation in River Bend.

On December 21, 1994, Cajun filed a petition in the United States Bankruptcy Court for the Middle District of Louisiana seeking bankruptcy relief under Chapter 11 of the United States Bankruptcy Code. Cajun's bankruptcy could have a material adverse effect on GSU, including the possibility of an NRC action with respect to the operation of River Bend. However, GSU is taking appropriate steps to protect its interests and its claims against Cajun arising from the co-ownership in River Bend and Big Cajun 2, Unit 3. On December 31, 1994, the District Court issued an order lifting an automatic stay as to certain proceedings, with the result that the preliminary injunction granted by the Court on December 19, 1994, remains in effect. Cajun filed a Notice of Appeal on January 18, 1995, to the United States Court of Appeals for the Fifth Circuit seeking a reversal of the District Court's grant of the preliminary injunction. No hearing date has been set on Cajun's appeal.

In the bankruptcy proceedings, Cajun filed on January 10, 1995, a motion to reject the River Bend Operating Agreement as a burdensome executory contract. GSU responded on January 10, 1995, with a memorandum opposing Cajun's motion filed with the District Court. This memorandum argues that the motion should be denied because (1) the Operating Agreement is not an executory contract that can be rejected under the United States Bankruptcy Code, but an agreement establishing property rights and obligations; (2) Cajun legally cannot have its payment obligations under the Operating Agreement suspended while retaining the benefits from co-ownership in River Bend, as the benefits and obligations are indivisible; (3) Cajun cannot seek to dispose of its property interest in River Bend or reject the Operating Agreement with respect thereto without disposing of all of its property interests and rejecting all of the arrangements under the River Bend package of agreements consisting of the Operating Agreement, Big Cajun 2, Unit 3 facility, certain transmission lines and the buy-back agreement pursuant to when GSU paid Cajun approximately $600 million for River Bend capacity and energy during the early years of operation of River Bend; and (4) a legal determination of Cajun's obligations and interests in River Bend should only be made as part of a plan of reorganization in bankruptcy and such determination should be subject to regulatory approvals by certain agencies with jurisdiction over Cajun, including the NRC. If the court were to grant Cajun's motion to reject the Operating Agreement, Cajun would be relieved of its financial obligations under the contract, while GSU would likely have a substantial damage claim arising from any such rejection. Although GSU believes that Cajun's motion to reject the Operating Agreement is non-meritorious, it is not possible to predict the outcome or ultimate impact of these proceedings.

During the period in which Cajun is not paying its share of River Bend costs, GSU intends to fund all costs necessary for the safe, continuing operation of the unit. The responsibilities of Entergy Operations as the licensed operator of River Bend, for safely operating and maintaining the unit are not affected by Cajun's actions.

The total resulting from Cajun's failure to fund repair projects, Cajun's funding limitation on refueling outages, and the weekly funding limitation by Cajun was $55.6 million as of December 31, 1994, compared with $33.3 million as of December 31, 1993. These amounts are reflected in long-term receivables with an offsetting reserve in other deferred credits. Cajun's bankruptcy may affect the ultimate collectibility of the amounts owed to GSU, including any amounts that may be awarded in litigation.

In September 1994, in connection with Entergy Corporation's analysis of certain preacquisition contingencies, Entergy Corporation increased its acquisition adjustment and GSU recorded a loss provision associated with the River Bend litigation between GSU and Cajun and certain underpayments by Cajun of River Bend costs, in accordance with SFAS 5, "Accounting for Contingencies." See Note 13 for additional information on provisions for preacquisition contingencies recorded during 1994.

Cajun - Transmission Service

GSU and Cajun are parties to FERC proceedings relating to transmission service charge disputes. In April 1992, FERC issued a final order. In May 1992, GSU and Cajun filed motions for rehearings which are pending at FERC. In June 1992, GSU filed a petition for review in the United States Court of Appeals regarding certain of the issues decided by FERC. In August 1993, the United States Court of Appeals rendered an opinion reversing the FERC order regarding the portion of such disputes relating to the calculations of certain credits and equalization charges under GSU's service schedules with Cajun. The opinion remanded the issues to FERC for further proceedings consistent with its opinion. In December 1994, FERC held a hearing to address the issues remanded by the Court of Appeals. In February 1995, FERC clarified its order, eliminating an issue that GSU believes the Court of Appeals directed FERC to reconsider.

GSU interprets the 1992 FERC order and the United States Court of Appeals' decision to mean that Cajun would owe GSU approximately $93.3 million as of December 31, 1994. However, FERC's February 1995 order indicates that FERC believes an issue, estimated by GSU to constitute approximately $26.2 million of this amount, may not be pursued by GSU in the remand proceedings. GSU further estimates that if it prevails in its May 1992 motion for rehearing, Cajun would owe GSU approximately $129.6 million as of December 31, 1994. If Cajun were to prevail in its May 1992 motion for rehearing to FERC, and if GSU were not to prevail in its May 1992 motion for rehearing to FERC, and if FERC does not implement the court's remand as GSU contends is required, GSU estimates it would owe Cajun approximately $85.6 million as of December 31, 1994. The above amounts are exclusive of a $7.3 million payment by Cajun on December 31, 1990, which the parties agreed to apply to the disputed transmission service charges. GSU and Cajun further agreed that their positions at FERC would remain unaffected by the $7.3 million payment. Pending FERC's ruling on the May 1992 motions for rehearing, GSU has continued to bill Cajun utilizing the historical billing methodology and has booked underpaid transmission charges, including interest, in the amount of $160.2 million as of December 31, 1994. This amount is reflected in long-term receivables with an offsetting reserve in other deferred credits.

Capital Requirements and Financing

Construction expenditures (excluding nuclear fuel) for the years 1995, 1996, and 1997 are estimated to total $177 million each year. GSU will also require $375 million during the period 1995-1997 to meet long-term debt and preferred stock maturities and sinking fund requirements. GSU plans to meet the above requirements with internally generated funds and cash on hand. See Notes 5 and 6 regarding the possible issuance, refunding, redemption, purchase or other acquisition of certain outstanding series of preferred stock and long-term debt.

Nuclear Insurance

The Price-Anderson Act limits public liability for a single nuclear incident to approximately $8.92 billion as of December 31, 1994. GSU has protection for this liability through a combination of private insurance (currently $200 million) and an industry assessment program. Under the assessment program, the maximum amount that would be required for each nuclear incident would be $79.3 million per reactor, payable at a rate of $10 million per licensed reactor per incident per year. GSU has one licensed reactor. Any assessments pertaining to this program are subject to the allocation in accordance with the respective ownership interests of GSU and Cajun. In addition, GSU participates in a private insurance program which provides coverage for worker tort claims filed for bodily injury caused by radiation exposure. GSU's maximum assessment under the program is an aggregate of approximately $3.2 million in the event losses exceed accumulated reserve funds.

GSU and Cajun are members of certain insurance programs that provide coverage for property damage, including decontamination and premature decommissioning expense, to members' nuclear generating plants. As of December 31, 1994, GSU was insured against such losses up to $2.75 billion with $250 million of this amount designated to cover any shortfall in the NRC required decommissioning trust funding. In addition, GSU is a member of an insurance program that covers certain replacement power and business interruption costs incurred due to prolonged nuclear unit outages. Under the property damage and replacement power/business interruption insurance programs, GSU could be subject to assessments if losses exceed the accumulated funds available to the insurers. As of December 31, 1994, the maximum amount of such possible assessments to GSU was $22.6 million. Cajun shares approximately $4.4 million of GSU's obligation.

The amount of property insurance presently carried by GSU exceeds the NRC's minimum requirement for nuclear power plant licensees of $1.06 billion per site. NRC regulations provide that the proceeds of this insurance must be used, first, to place and maintain the reactor in a safe and stable condition and, second, to complete decontamination operations. Only after proceeds are dedicated for such use and regulatory approval is secured, would any remaining proceeds be made available for the benefit of plant owners or their creditors.

Spent Nuclear Fuel and Decommissioning Costs

GSU provides for estimated future disposal costs for spent nuclear fuel in accordance with the Nuclear Waste Policy Act of 1982. GSU entered into a contract with the DOE, whereby the DOE will furnish disposal service at a cost of one mill per net KWH generated and sold. The fees payable to the DOE may be adjusted in the future to assure full recovery. GSU considers all costs incurred or to be incurred for the disposal of spent nuclear fuel to be proper components of nuclear fuel expense, and provisions to recover such costs have been or will be made in applications to regulatory authorities.

Delays have occurred in the DOE's program for the acceptance and disposal of spent nuclear fuel at a permanent repository. In a statement released February 17, 1993, the DOE asserted that it does not have a legal obligation to accept spent nuclear fuel without an operational repository for which it has not yet arranged. Currently the DOE projects it will begin to accept spent fuel no earlier than 2010. In the meantime, GSU is responsible for spent fuel storage. Current on-site spent fuel storage capacity at River Bend is estimated to be sufficient until 2003. Thereafter, GSU will provide additional storage capacity at an initial cost of $5 million to $10 million. In addition, approximately $3 million to $5 million will be required every four to five years subsequent to 2003 until the DOE's repository program begins accepting River Bend's spent fuel.

Entergy Operations and System Fuels joined in lawsuits against the DOE, seeking clarification of the DOE's responsibility to receive spent nuclear fuel beginning in 1998. The original suits, filed June 20, 1994, asked for a ruling stating that the Nuclear Waste Policy Act require the DOE to begin taking title to the spent fuel and to start removing it from nuclear power plants in 1998, a mandate for the DOE's nuclear waste management program to begin accepting fuel in 1998 and court monitoring of the program, and the potential for escrow of payments to the Nuclear Waste Fund instead of directly to the DOE.

GSU is recovering in rates amounts sufficient to fund decommissioning costs for River Bend, based on the original 1985 decommissioning cost study of approximately $141 million, which relates to GSU's 70% interest in River Bend. The amounts recovered in rates are deposited in external trust funds and reported at market value. The accumulated decommissioning liability of $22.2 million as of December 31, 1994, has been recorded in accumulated depreciation. Decommissioning expense amounting to $3.0 million was recorded in 1994. A more recent 1991 engineering study indicates decommissioning costs for GSU's 70% interest may be $267.8 million (in 1990 dollars). GSU filed the more recent cost study with the PUCT requesting a rate adjustment for decommissioning expense. As discussed in Note 2, on March 20, 1995, the PUCT ruled in the current rate case. The PUCT order included recovery of River Bend decommissioning costs totaling $204.9 million. GSU plans to ask the LPSC for a rate adjustment for decommissioning expense in conjunction with its next rate review in mid 1995. The actual decommissioning costs may vary from the estimates because of regulatory requirements, changes in technology, and increased costs of labor, materials, and equipment. Management believes that actual decommissioning costs are likely to be higher than the amounts presented above.

The staff of the SEC has questioned certain of the current accounting practices of the electric utility industry, regarding the recognition, measurement, and classification of decommissioning costs for nuclear generating stations in the financial statements of electric utilities. In response to these questions, the FASB is

currently reviewing the accounting for decommissioning. If current electric utility industry accounting practices for such decommissioning are changed, annual provisions for decommissioning could increase, the estimated cost for decommissioning could be recorded as a liability rather than as accumulated depreciation, and trust fund income from the external decommissioning trusts could be reported as investment income rather than as a reduction to decommissioning expense.

The EPAct has a provision that assesses domestic nuclear utilities with fees for the decontamination and decommissioning of the DOE's past uranium enrichment operations. The decontamination and decommissioning assessments will be used to set up a fund into which contributions from utilities and the federal government will be placed. GSU's annual assessment, which will be adjusted annually for inflation, is $0.9 million (in 1995 dollars) for approximately 15 years. FERC requires that utilities treat these assessments as costs of fuel as they are amortized. The liability of $6.6 million as of December 31, 1994, is recorded in other current liabilities and other noncurrent liabilities and is offset in financial statements by a regulatory asset.

Long-Term Contracts

NISCO Power Purchases. In 1988, GSU entered into a joint venture with a primary term of 20 years with Conoco, Inc., Citgo Petroleum Corporation, and Vista Chemical Company (Industrial Participants) whereby GSU's Nelson Units 1 and 2 were sold to a partnership (NISCO) consisting of the Industrial Participants and GSU. The Industrial Participants are supplying the fuel for the units, while GSU operates the units at the discretion of the Industrial Participants and purchases the electricity produced by the units. GSU is continuing to sell electricity to the Industrial Participants. For the years ended December 31, 1994, 1993, and 1992, the purchases of electricity from the joint venture totaled $58.3 million, $62.6 million, and $37.8 million, respectively.

Natural Gas Contracts. GSU has long-term gas contracts which will satisfy approximately 75% of its annual requirements. However, such contracts as a whole only require GSU to purchase in the range of 40% of expected total gas needs. Additional gas requirements are satisfied under less expensive short-term contracts. GSU entered into a transportation service agreement which obligated the gas supplier to provide GSU with flexible natural gas swing service to the Sabine and Lewis Creek generating stations. This service is provided by the supplier's pipeline and salt dome gas storage facility, which has a present capacity of 5.3 billion cubic feet of natural gas.

Coal Contracts. GSU has contracted for a long-term supply of low-sulfur Wyoming coal for use at Nelson Unit 6. This contract, which is set to expire in 2004, will provide a supply of 50 million tons over the term of the contract. Cajun has advised GSU that current contracts will provide an adequate supply of coal for Big Cajun 2, Unit 3 until 1997.

Environmental Issues

GSU has been notified by the U. S. Environmental Protection Agency (EPA) that it has been designated as a potentially responsible party for the cleanup of sites on which GSU and others have or have been alleged to have disposed of material designated as hazardous waste. GSU is currently negotiating with the EPA and state authorities regarding the cleanup of some of these sites. Several class action and other suits have been filed in state and federal courts seeking relief from GSU and others for damages caused by the disposal of hazardous waste and for asbestos-related disease allegedly resulting from exposure on GSU premises. While the amounts at issue in the cleanup efforts and suits may be substantial, GSU believes that its results of operations and financial condition will not be materially affected by the outcome of the suits.

As of December 31, 1994, GSU has accrued cumulative amounts related to the cleanup of six sites at which GSU has been designated a potentially responsible party, totaling $27.7 million since 1990. Through December 31, 1994, GSU has expended $7.4 million cumulatively on the cleanup, resulting in a remaining recorded liability of $20.3 million as of December 31, 1994

Sales/Use Tax Issues

In September 1994, the Louisiana Supreme Court (Court) issued an opinion (in a case in which none of the System companies was a party) holding, in part that the Louisiana state legislature's suspension of state sales and use tax exemptions also had the effect of suspending exemptions from local sales and use taxes. On January 27, 1995 the Court, after rehearing, reversed its opinion. Because of the Court's most recent ruling, sales of electricity and gas, fuels and other items used by GSU, LP&L, and NOPSI to generate electricity in Louisiana, as well as other items exempt from sales and use taxes, continue to be exempt from local sales and use taxes, even though the state exemptions for sales and use tax have been suspended.

NOTE 9. LEASES

General

As of December 31, 1994, GSU had capital leases and noncancelable operating leases (excluding nuclear fuel leases) with minimum lease payments as follows:

Year	Capital Leases	Operating Leases
	(In Thousands)	
1995	$ 12,475	$ 10,695
1996	12,475	10,135
1997	12,475	13,742
1998	12,475	13,703
1999	12,475	13,703
Years thereafter	81,380	92,597
Minimum lease payments	143,755	$154,575
Less: Amount representing interest	55,651	
Present value of net minimum lease payments	$ 88,104	

Rental expense for capital and operating leases (excluding nuclear fuel leases) amounted to approximately $15.3, $31.9 million, and $21.9 million in 1994, 1993, and 1992, respectively.

GSU is leasing the Lewis Creek generating station from its wholly owned consolidated subsidiary, GSG&T.

Nuclear Fuel Lease

GSU has arrangements to lease nuclear fuel in an amount up to $105 million. The lessor finances its acquisition of nuclear fuel through a credit agreement and the issuance of notes. The credit agreement, which was entered into in 1993, has been extended to December 1997 and the notes have varying remaining maturities of up to 3 years. It is expected that the credit arrangement will be extended or alternative financing will be secured by the lessor upon the maturity of the current arrangements. If the lessor cannot arrange for alternative financing upon the maturity of its borrowings, GSU must purchase nuclear fuel in an amount sufficient to enable the lessor to retire such borrowings.

Lease payments are based on nuclear fuel use. Nuclear fuel expense of $37.2 million, $43.6 million, and $31.6 million (including interest of $8.7 million, $10.2 million, and $11.5 million) was charged to operations in 1994, 1993, and 1992, respectively.

NOTE 10. POSTRETIREMENT BENEFITS

Pension Plan

GSU has a defined benefit pension plan covering substantially all of its employees. The pension plan is noncontributory and provides pension benefits that are based on employees' credited service and the average compensation generally during the last five years before retirement. GSU funds pension costs in accordance with contribution guidelines established by the Employee Retirement Income Security Act of 1974, as amended, and the Internal Revenue Code of 1986, as amended. The assets of the plan consist primarily of common and preferred stocks and fixed income securities. In 1994, GSU amended its defined benefit pension plan for non-bargaining unit employees to be consistent with the other System companies. Additionally, actuarial assumptions were also changed to be consistent with the other System companies.

GSU's 1994, 1993, and 1992 pension cost, including amounts capitalized, included the following components:

	For the Years Ended December 31,		
	1994	1993	1992
		(In Thousands)	
Service cost - benefits earned during the period	$ 9,497	$ 10,417	$ 12,396
Interest cost on projected benefit obligation	21,335	17,643	16,307
Actual return on plan assets	6,785	(43,400)	(28,117)
Net amortization and deferral	(39,405)	14,863	2,926
Other	17,963	-	-
Net pension cost	$ 16,175	$ (477)	$ 3,512

The funded status of GSU's pension plan as of December 31, 1994 and 1993, was:

	1994	1993
	(In Thousands)	
Actuarial present value of benefit obligations:		
Vested	$273,509	$227,820
Nonvested	1,502	13,667
Accumulated benefit obligation	$275,011	$241,487
Plan assets at fair market value	$313,035	$337,922
Projected benefit obligation	290,802	282,722
Plan assets in excess of projected benefit obligation	22,233	55,200
Unrecognized prior service cost	13,720	11,985
Unrecognized transition asset	(14,324)	(16,712)
Unrecognized net gain	(73,423)	(86,092)
Accrued pension liability	$(51,794)	$(35,619)

The accrued pension liability for G U for 1993 has been restated to include liabilities for certain Early Retirement Programs. Prior to 1994, GSU accounted for such Early Retirement Programs in separate liability accounts other than the pension liability. However, effective in 1994, GSU changed its policy to include such liabilities in the pension liability account to be consistent with the other System companies. The significant actuarial assumptions used in computing the information above for 1994, 1993, and 1992 were as follows: weighted average discount rate, 8.5% for 1994, 7.5% for 1993, and 6.50% for 1992; weighted average rate of increase in future compensation levels, 5.1% for 1994, 5.0% for 1993, and 5.75% for 1992; and expected long-term rate of return on plan assets, 8.5%. Transition assets are being amortized over 15 years.

In December 1993, GSU recorded a $17.0 million charge related to the announced early retirement program in connection with the Merger, of which $14.9 million was expensed. In 1994, GSU recorded an additional $18.0 million charge related to early retirement programs in connection with the Merger, of which $15.2 million was expensed.

Other Postretirement Benefits

GSU also provides certain health care and life insurance benefits for retired employees. All of GSU's employees may become eligible for these benefits if they reach retirement age while still working for GSU. The cost of providing these benefits, recorded on a cash basis, was $5.3 million for 1992.

Effective January 1, 1993, GSU adopted SFAS 106. This standard required a change from a cash method to an accrual method of accounting for postretirement benefits other than pensions. GSU continues to fund these benefits on a pay-as-you-go-basis. As of January 1, 1993, the actuarially determined accumulated postretirement benefit obligation (APBO) earned by retirees and active employees was estimated to be approximately $128 million. This obligation is being amortized over a 20-year period beginning in 1993. In 1994, GSU changed its actuarial assumptions and attribution methodology to be consistent with the other System companies.

In March 1993, the PUCT issued a ruling applicable to all Texas utilities that amounts recorded in compliance with SFAS 106 and included in a rate filing test period, will be recoverable in rates (at the time of the next general rate case) and that the postretirement benefit amounts allowed in rates must then be funded by the utility. The PUCT made no specific provision in its order permitting deferral, as a regulatory asset, of these costs.

The LPSC ordered GSU to use the pay-as-you-go method for ratemaking purposes for postretirement benefits other than pensions, but the LPSC retains the flexibility to examine companies' accounting for postretirement benefits to determine if special exceptions to this order are warranted.

GSU's 1994 and 1993 postretirement benefit cost, including amounts capitalized and deferred, included the following components:

	1994	1993
	(In Thousands)	
Service cost - benefits earned during the period	$ 2,169	$ 5,467
Interest cost on APBO	6,449	9,976
Actual return on plan assets	-	-
Net amortization and deferral	2,832	6,402
Net periodic postretirement benefit cost	$11,450	$21,845

The funded status of GSU's postretirement plan as of December 31, 1994 and 1993, was:

	1994	1993
	(In Thousands)	
Accumulated postretirement benefit obligation:		
Retirees	$ 39,695	$ 46,270
Other fully eligible participants	26,069	38,091
Other active participants	13,445	18,359
	79,209	102,720
Plan assets at fair value	-	-
Plan assets in excess of (less than APBO)	(79,209)	(102,720)
Unrecognized transition obligation	115,232	121,634
Unrecognized net loss (gain)	(57,410)	(35,534)
Accrued postretirement benefit liability	$ (21,387)	$ (16,620)

The assumed health care cost trend rate used in measuring the APBO is 9.4% for 1995, gradually decreasing each successive year until it reaches 5% in 2011. A one percentage-point increase in the assumed health care cost trend rate for each year would increase the APBO as of December 31, 1994, by 10.3% and the sum of the service cost and interest cost by approximately 12.2%. The assumed discount rate and rate of increase in future compensation used in determining the APBO were 8.5% for 1994 and 7.5% for 1993, and 5.1% for 1994 and 5% for 1993, respectively.

NOTE 11. TRANSACTIONS WITH AFFILIATES

GSU purchases electricity from and/or sells electricity to the other System operating companies, subsequent to the Merger, under rate schedules filed with FERC. In addition, GSU receives technical and advisory services from Entergy Services, and receives management and operating services from Entergy Operations.

Operating revenues include revenues from sales to System operating companies amounting to $44.4 million in 1994. Operating expenses include charges from System operating companies for purchased power and related charges totaling $296.9 million in 1994, and $25.5 million in 1993, and $38.8 million in 1992, prior to the Merger. GSU pays directly or reimburses Entergy Operations for costs associated with operating River Bend (excluding nuclear fuel) which were approximately $210.2 million in 1994.

NOTE 12. RESTRUCTURING COSTS

During the third quarter of 1994, GSU announced a restructuring program related to certain of its operating units. The program is designed to reduce costs, improve operating efficiencies, and increase shareholder value in order to enable GSU to become a low-cost producer. The program includes reductions in the number of employees and the consolidation of offices and facilities. In 1994, GSU recorded restructuring charges of $6.5 million. These charges primarily include employee severance costs related to the expected termination of approximately 450 employees. As of December 31, 1994, no employees have been terminated and no termination benefits have been paid under this restructuring program.

NOTE 13. ENTERGY CORPORATION-GSU MERGER

On December 31, 1993, Entergy Corporation and GSU consummated their Merger. GSU became a wholly-owned subsidiary of Entergy Corporation and continues to operate as a corporation under the regulation of FERC, the PUCT, and the LPSC. As consideration to GSU's shareholders, Entergy Corporation paid $250 million and issued 56,695,724 shares of its common stock in exchange for the 114,055,065 outstanding shares of GSU common stock.

As a result of the December 31, 1993 Merger closing, GSU recorded expenses totaling $49 million, net of related tax effects, for early retirement and other severance related plans and the payment to financial consultants involved in Merger negotiations on behalf of GSU. Additionally, GSU recorded $23.8 million in 1994 for remaining severance and augmented retirement benefits related to the Merger. See Note 2 for information regarding Merger-related rate agreements.

In 1993, Entergy Corporation recorded an acquisition adjustment in utility plant in the amount of $380 million representing the excess of the purchase price over the net assets acquired of GSU. The acquisition adjustment will be amortized on a straight-line basis over a 31-year period, which approximates the remaining average book life of GSU's plant. During the allocation period (which expired on December 31, 1994), Entergy Corporation completed its analyses with respect to preacquisition contingencies and revised the allocation of the purchase price for a number of preacquisition contingencies. In 1994, GSU wrote-off assets or recorded liabilities totaling approximately $137 million net of tax for the Cajun-River Bend litigation, unfunded Cajun-River Bend costs, environmental cleanup costs, obsolete spare parts, Louisiana River Bend rate deferrals previously disallowed by the LPSC, plant held for future use, and the PUCT Fuel Reconciliation Settlement. Any items recorded in 1995 or later, will result in write-offs and/or losses charged to operations on GSU's financial statements and Entergy Corporation's consolidated financial statements.

NOTE 14. QUARTERLY FINANCIAL DATA (UNAUDITED)

GSU's business is subject to seasonal fluctuations with the peak period occurring during the third quarter. Operating results for the four quarters of 1994 and 1993 were:

	Operating Revenues	Operating Income	Income (Loss) Before Extraordinary Items and the Cumulative Effect of Accounting Changes	Net Income (Loss)
		(In Thousands)		
1994:				
First Quarter	$429,658	$ 58,561	$ 11,043	$ 11,043
Second Quarter	$456,855	$ 83,357	$ 33,084	$ 33,084
Third Quarter	$545,531	$ 64,853	$ (31,662)	$ (31,662)
Fourth Quarter	$365,321	$ 6,880	$ (95,220)	$ (95,220)
1993:				
First Quarter	$404,178	$ 69,408	$ 15,007	$ 25,667
Second Quarter	$442,223	$ 81,989	$ 31,066	$ 30,781
Third Quarter	$574,607	$118,032	$ 70,155	$ 69,181
Fourth Quarter	$406,612	$ 1,187	$ (46,767)	$ (46,767)

See Note 2 for information regarding the recording of a reserve for rate refund in December 1994, Note 12 for information regarding the recording of certain restructuring costs in 1994, and Note 13 for information regarding the recording of charges associated with certain preacquisition contingencies in 1994.

See Note 1 for information regarding the change in accounting for unbilled revenues in 1993. See Note 2 for information regarding rate refunds during December 1993, and Note 13 for information regarding Merger-related charges recorded during the fourth quarter of 1993.

GULF STATES UTILITIES COMPANY

SELECTED FINANCIAL DATA - FIVE-YEAR COMPARISON

	1994	1993	1992	1991	1990
			(In Thousands)		
Operating revenues	$1,797,365	$1,827,620	$1,773,374	$1,702,235	$1,690,685
Income (loss) before extraordinary items and the cumulative effect of accounting changes	$ (82,755)	$ 69,461	$ 139,413	$ 112,391	$ (36,399)
Total assets	$6,843,461	$7,137,351	$7,164,447	$7,183,119	$7,135,399
Long-term obligations (1)	$2,689,042	$2,772,002	$2,798,768	$2,816,577	$2,663,249

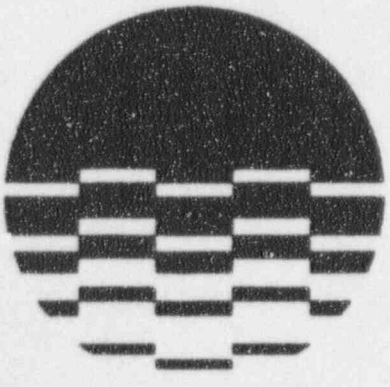
(1) Includes long-term debt (excluding currently maturing debt), preferred and preference stock with sinking fund, and noncurrent capital lease obligations.

See Notes 1 and 10 for the effect of accounting changes in 1993 and 1992 and Notes 2 and 8 regarding River Bend rate appeals and litigation with Cajun.

	1994	1993	1992	1991	1990
			(Dollars in Thousands)		
Electric Department					
Operating Revenues:					
Residential	$ 569,997	$ 585,799	$ 560,552	$ 547,147	$ 523,911
Commercial	414,929	415,267	400,803	383,883	378,253
Industrial	626,047	650,230	642,298	582,568	578,928
Governmental	25,242	26,118	26,195	24,792	24,101
Total retail	1,636,215	1,677,414	1,629,848	1,538,390	1,505,193
Sales for resale	98,230	31,898	24,485	44,136	48,125
Other	(15,244)	38,649	40,203	41,433	43,317
Total Electric Department	$1,719,201	$1,747,961	$1,694,536	$1,623,959	$1,596,635
Billed Electric Energy Sales (Millions of KWH):					
Electric Department					
Residential	7,351	7,192	6,825	6,925	6,834
Commercial	6,089	5,711	5,474	5,460	5,388
Industrial	15,026	14,294	14,413	13,629	13,347
Governmental	297	296	302	295	285
Total retail	28,763	27,493	27,014	26,309	25,854
Sales for resale	3,516	666	540	1,049	1,180
Total Electric Department	32,279	28,159	27,554	27,358	27,034
Steam Department	1,659	1,597	1,722	1,711	1,930
Total	33,938	29,756	29,276	29,069	28,964

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Louisiana Power & Light Company/1994 Financial Statements



LP&L

LOUISIANA POWER & LIGHT COMPANY

DEFINITIONS

Certain abbreviations or acronyms used in LP&L's Financial Statements, Notes to Financial Statements, and Management's Financial Discussion and Analysis are defined below:

Abbreviation or Acronym	Term
AFUDC	Allowance for Funds Used During Construction
AP&L	Arkansas Power & Light Company
DOE	United States Department of Energy
Entergy or System	Entergy Corporation and its various direct and indirect subsidiaries
Entergy Operations	Entergy Operations, Inc., a subsidiary of Entergy Corporation that has operating responsibility for Grand Gulf 1, Waterford 3, ANO, and River Bend
Entergy Services	Entergy Services, Inc.
EPAct	The Energy Policy Act of 1992
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
Grand Gulf 1	Unit No. 1 of the Grand Gulf Station (nuclear)
Grand Gulf 2	Unit No. 2 of the Grand Gulf Station (nuclear)
Grand Gulf Station	Grand Gulf Steam Electric Generating Station (nuclear)
GSU	Gulf States Utilities Company (including wholly owned subsidiaries - Varibus Corporation, GSG&T, Inc., Prudential Oil and Gas, Inc., and Southern Gulf Railway Company)
KWH	Kilowatt-Hour(s)
LP&L	Louisiana Power & Light Company
LPSC	Louisiana Public Service Commission
Money Pool	Entergy Money Pool, which allows certain System companies to borrow from, or lend to, certain other System companies
MP&L	Mississippi Power & Light Company
NOPSI	New Orleans Public Service Inc.

Abbreviation or Acronym	Term
OBRA	Omnibus Budget Reconciliation Act of 1993
Owner Participant	A corporation that, in connection with the Waterford 3 sale and leaseback transactions, has acquired a beneficial interest in a trust, the Owner Trustee of which is the owner and lessor of an undivided interest in Waterford 3
Owner Trustee	Each institution and/or individual acting as owner trustee under a trust agreement with an Owner Participant in connection with the Waterford 3 sale and leaseback transactions
SEC	Securities and Exchange Commission
SFAS	Statement of Financial Accounting Standards promulgated by the FASB
SFAS 106	SFAS 106, "Employers' Accounting for Postretirement Benefits Other Than Pensions"
SFAS 109	SFAS 109, "Accounting for Income Taxes"
System or Entergy	Entergy Corporation and its various direct and indirect subsidiaries
System Energy	System Energy Resources, Inc.
System Fuels	System Fuels, Inc.
System operating companies	AP&L, GSU, LP&L, MP&L, and NOPSI, collectively
Waterford 3	Unit No. 3 of LP&L's Waterford Steam Electric Generating Station (nuclear)

LOUISIANA POWER & LIGHT COMPANY

REPORT OF MANAGEMENT

The management of Louisiana Power & Light Company has prepared and is responsible for the financial statements and related financial information included herein. The financial statements are based on generally accepted accounting principles. Financial information included elsewhere in this report is consistent with the financial statements.

To meet its responsibilities with respect to financial information, management maintains and enforces a system of internal accounting controls that is designed to provide reasonable assurance, on a cost-effective basis, as to the integrity, objectivity, and reliability of the financial records, and as to the protection of assets. This system includes communication through written policies and procedures, an employee Code of Conduct, and an organizational structure that provides for appropriate division of responsibility and the training of personnel. This system is also tested by a comprehensive internal audit program.

The independent public accountants provide an objective assessment of the degree to which management meets its responsibility for fairness of financial reporting. They regularly evaluate the system of internal accounting controls and perform such tests and other procedures as they deem necessary to reach and express an opinion on the fairness of the financial statements.

Management believes that these policies and procedures provide reasonable assurance that its operations are carried out with a high standard of business conduct.

EDWIN LUPBERGER
Chairman and Chief Executive Officer

GERALD D. MCINVALE
Senior Vice President and
Chief Financial Officer

LOUISIANA POWER & LIGHT COMPANY

AUDIT COMMITTEE CHAIRMAN'S LETTER

The Entergy Corporation Board of Directors' Audit Committee functions as the Audit Committee for Louisiana Power & Light Company. The Audit Committee is comprised of four directors, who are not officers of LP&L: H. Duke Shackelford (Chairman), Lucie J. Fjeldstad, Dr. Norman C. Francis, and James R. Nichols. The committee held four meetings during 1994.

The Audit Committee oversees LP&L's financial reporting process on behalf of the Board of Directors and provides reasonable assurance to the Board that sufficient operating, accounting, and financial controls are in existence and are adequately reviewed by programs of internal and external audits.

The Audit Committee discussed with Entergy's internal auditors and the independent public accountants (Coopers & Lybrand L.L.P.) the overall scope and specific plans for their respective audits, as well as LP&L's financial statements and the adequacy of LP&L's internal controls. The committee met, together and separately, with Entergy's internal auditors and independent public accountants, without management present, to discuss the results of their audits, their evaluation of LP&L's internal controls, and the overall quality of LP&L's financial reporting. The meetings also were designed to facilitate and encourage any private communication between the committee and the internal auditors or independent public accountants.

H. DUKE SHACKELFORD
Chairman, Audit Committee

REPORT OF INDEPENDENT ACCOUNTANTS

To the Board of Directors and Shareholders of
Louisiana Power & Light Company

We have audited the accompanying balance sheet of Louisiana Power & Light Company as of December 31, 1994, and the related statements of income, retained earnings and cash flows for the year then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audit. The financial statements of the Company as of December 31, 1993 and for the years ended December 31, 1993 and 1992, were audited by other auditors, whose report, dated February 11, 1994, included an explanatory paragraph that described changes in methods of accounting for income taxes and postretirement benefits other than pensions which are discussed in Notes 3 and 10 respectively, to these financial statements.

We conducted our audit in accordance with generally accepted auditing standards. Those standards require that we plan and perform the audit to obtain reasonable assurance 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 audit provides a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 1994, and the result of its operations and its cash flows for the year then ended in conformity with generally accepted accounting principles.

COOPERS & LYBRAND L.L.P.
New Orleans, Louisiana
February 21, 1995

LOUISIANA POWER & LIGHT COMPANY

AUDIT COMMITTEE CHAIRMAN'S LETTER

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H. DUKE SHACKELFORD
Chairman, Audit Committee

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In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 1994, and the result of its operations and its cash flows for the year then ended in conformity with generally accepted accounting principles.

COOPERS & LYBRAND L.L.P.
New Orleans, Louisiana
February 21, 1995

INDEPENDENT AUDITORS' REPORT

To the Shareholders and the Board of Directors of
Louisiana Power & Light Company

We have audited the accompanying balance sheet of Louisiana Power & Light Company (LP&L) as of December 31, 1993, and the related statements of income, retained earnings, and cash flows for each of the two years in the period ended December 31, 1993. These financial statements are the responsibility of LP&L's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with generally accepted auditing standards. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such financial statements present fairly, in all material respects, the financial position of LP&L at December 31, 1993, and the results of its operations and its cash flows for each of the two years in the period ended December 31, 1993 in conformity with generally accepted accounting principles.

As discussed in Notes 3 and 10 to the financial statements, in 1993 LP&L changed its methods of accounting for income taxes and postretirement benefits other than pensions, respectively.

DELOITTE & TOUCHE LLP
New Orleans, Louisiana
February 11, 1994

LOUISIANA POWER & LIGHT COMPANY
BALANCE SHEETS
ASSETS

	December 31,	
	1994	1993
	(In Thousands)	
Utility Plant:		
Electric	$4,778,126	$4,646,020
Electric plant under lease	229,468	225,083
Construction work in progress	94,791	133,536
Nuclear fuel under capital lease	44,238	61,375
Nuclear fuel	6,420	3,823
Total	5,153,043	5,069,837
Less - accumulated depreciation and amortization	1,600,510	1,496,107
Utility plant - net	3,552,533	3,573,730
Other Property and Investments:		
Nonutility property	20,060	20,060
Decommissioning trust fund	27,076	22,109
Investment in subsidiary company - at equity	14,230	14,230
Other	1,078	984
Total	62,444	57,383
Current Assets:		
Cash and cash equivalents:		
Temporary cash investments - at cost, which approximates market	28,718	33,489
Special deposits	3,237	19,077
Accounts receivable:		
Customer (less allowance for doubtful accounts of $1.2 million in 1994 and of $1.1 million in 1993)	58,858	66,575
Associated companies	9,827	2,952
Other	11,609	10,656
Accrued unbilled revenues	63,109	64,314
Accumulated deferred income taxes	3,702	6,031
Materials and supplies - at average cost	89,692	87,204
Rate deferrals	28,422	28,422
Prepayments and other	25,291	16,510
Total	322,465	335,230
Deferred Debits and Other Assets:		
Regulatory Assets:		
Rate deferrals	25,609	54,031
SFAS 109 regulatory asset - net	379,263	349,703
Unamortized loss on reacquired debt	43,656	47,853
Other regulatory assets	25,736	26,837
Other	23,733	19,231
Total	497,997	497,655
TOTAL	$4,435,439	$4,463,998

See Notes to Financial Statements.

LOUISIANA POWER & LIGHT COMPANY
BALANCE SHEETS
CAPITALIZATION AND LIABILITIES

	December 31,	
	1994	1993
	(In Thousands)	
Capitalization:		
Common stock, no par value, authorized 250,000,000 shares; issued and outstanding 165,173,180 shares in 1994 and 1993	$1,088,900	$1,088,900
Capital stock expense and other	(5,367)	(6,109)
Retained earnings	113,420	89,849
Total common shareholder's equity	1,196,953	1,172,640
Preferred stock:		
Without sinking fund	160,500	160,500
With sinking fund	111,265	126,302
Long-term debt	1,403,055	1,457,626
Total	2,871,773	2,917,068
Other Noncurrent Liabilities:		
Obligations under capital leases	16,238	27,508
Other	54,216	28,909
Total	70,454	56,417
Current Liabilities:		
Currently maturing long-term debt	75,320	25,315
Notes payable:		
Associated companies	7,954	52,041
Other	19,200	-
Accounts payable:		
Associated companies	20,793	33,523
Other	82,203	76,284
Customer deposits	54,934	52,234
Taxes accrued	(1,860)	15,110
Interest accrued	42,987	42,141
Dividends declared	5,489	5,938
Deferred revenue - gas supplier judgment proceeds	-	14,632
Deferred fuel cost	13,983	605
Obligations under capital leases	28,000	33,867
Other	20,156	9,741
Total	369,159	361,431
Deferred Credits:		
Accumulated deferred income taxes	883,945	834,899
Accumulated deferred investment tax credits	151,259	188,843
Deferred interest - Waterford 3 lease obligation	26,000	25,372
Other	62,849	79,968
Total	1,124,053	1,129,082
Commitments and Contingencies (Notes 2, 8, and 9)		
TOTAL	$4,435,439	$4,463,998

See Notes to Financial Statements.

LOUISIANA POWER & LIGHT COMPANY
STATEMENTS OF CASH FLOWS

	For the Years Ended December 31,		
	1994	1993	1992
		(In Thousands)	
Operating Activities:			
Net income	$213,839	$188,808	$182,989
Noncash items included in net income:			
Change in rate deferrals	28,422	28,422	28,422
Depreciation and decommissioning	151,994	142,051	138,290
Deferred income taxes and investment tax credits	(15,972)	40,261	42,896
Allowance for equity funds used during construction	(3,486)	(2,581)	(1,714)
Amortization of deferred revenues	(14,632)	(42,470)	(38,646)
Changes in working capital:			
Receivables	1,094	(8,046)	(5,135)
Accounts payable	(6,811)	(28,198)	7,733
Taxes accrued	(16,970)	6,861	6,002
Interest accrued	846	1,003	2,917
Other working capital accounts	31,064	15,205	(16,037)
Refunds to customers - gas contract settlement	-	(56,027)	(56,066)
Decommissioning trust contributions	(4,815)	(4,000)	(2,000)
Other	3,048	18,299	5,982
Net cash flow provided by operating activities	367,621	299,588	295,633
Investing Activities:			
Construction expenditures	(140,669)	(163,142)	(150,527)
Allowance for equity funds used during construction	3,486	2,581	1,714
Net cash flow used in investing activities	(137,183)	(160,561)	(148,813)
Financing Activities:			
Proceeds from the issuance of:			
First mortgage bonds	-	100,000	269,000
Preferred stock	-	-	87,000
Other long-term debt	19,946	58,000	44,094
Changes in short-term borrowings	(24,887)	52,041	-
Retirement of:			
First mortgage bonds	(25,000)	(100,919)	(309,205)
Other long-term debt	(322)	(22,052)	(15,977)
Redemption of preferred stock	(15,038)	(22,500)	(63,981)
Dividends paid:			
Common stock	(167,100)	(167,600)	(174,600)
Preferred stock	(22,808)	(25,290)	(28,845)
Net cash flow used in financing activities	(235,209)	(128,320)	(192,514)
Net increase (decrease) in cash and cash equivalents	(4,771)	10,707	(45,694)
Cash and cash equivalents at beginning of period	33,489	22,782	68,476
Cash and cash equivalents at end of period	$28,718	$33,489	$22,782
SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION:			
Cash paid during the period for:			
Interest - net of amount capitalized	$128,000	$127,497	$126,674
Income taxes	$96,442	$62,414	$32,668
Noncash investing and financing activities:			
Capital lease obligations incurred	$9,677	$33,210	$37,689
Deficiency of fair value of decommissioning trust assets over amount invested	($1,129)	-	-

See Notes to Financial Statements.

LIQUIDITY AND CAPITAL RESOURCES

Liquidity is important to LP&L due to the capital intensive nature of its business, which requires large investments in long-lived assets. While large capital expenditures for the construction of new generating capacity are not currently planned, LP&L does require significant capital resources for the periodic maturity of certain series of debt and preferred stock and ongoing construction. Net cash flow from operations totaled $368 million, $300 million, and $296 million in 1994, 1993, and 1992, respectively. Net cash flow from operations in 1993 included payment of the last scheduled refund to customers of proceeds from a settlement with a gas supplier. In recent years, this cash flow, supplemented by cash on hand, has been sufficient to meet substantially all investing and financing requirements, including capital expenditures, dividends, and debt/preferred stock maturities. LP&L's ability to fund these capital requirements results, in part, from its continued efforts to streamline operations and reduce costs, as well as collections under its Waterford 3 rate phase-in plan which exceed the current cash requirements for Waterford 3-related costs. (In the income statement, these revenue collections are offset by the amortization of previously deferred costs; therefore, there is no effect on net income.) LP&L's Waterford 3 rate phase-in plan will continue to contribute to LP&L's cash position through 1996. See Note 2 for additional information on LP&L's rate phase-in plan. See Note 8 for additional information on LP&L's capital and refinancing requirements in 1995 - 1997. Also, to the extent current market interest and dividend rates allow, LP&L may continue to refinance high-cost debt and preferred stock prior to maturity.

Earnings coverage tests and bondable property additions limit the amount of first mortgage bonds and preferred stock that LP&L can issue. Based on the most restrictive applicable tests as of December 31, 1994, and assuming an annual interest or dividend rate of 9.25%, LP&L could have issued $107 million of additional first mortgage bonds or $784 million of additional preferred stock. Further, LP&L has the conditional ability to issue first mortgage bonds against the retirement of first mortgage bonds, in some cases without satisfying an earnings coverage test.

See Notes 5 and 6 for information on LP&L's financing activities and Note 4 for information on LP&L's short-term borrowings and lines of credit.

LOUISIANA POWER & LIGHT COMPANY
STATEMENTS OF INCOME

	For the Years Ended December 31,		
	1994	1993	1992
		(In Thousands)	
Operating Revenues	$1,708,541	$1,729,666	$1,553,745
Operating Expenses:			
Operation and maintenance:			
Fuel and fuel-related expenses	331,422	338,670	256,313
Purchased power	366,564	381,252	335,750
Nuclear refueling outage expenses	18,187	18,380	19,179
Other operation and maintenance	348,980	340,320	324,020
Depreciation and decommissioning	151,994	142,051	138,290
Taxes other than income taxes	56,101	50,391	49,507
Income taxes	63,751	108,568	83,984
Amortization of rate deferrals	28,422	28,422	28,422
Total	1,365,421	1,408,054	1,235,465
Operating Income	343,120	321,612	318,280
Other Income (Deductions):			
Allowance for equity funds used during construction	3,486	2,581	1,714
Miscellaneous - net	747	2,069	6,676
Income taxes	463	(2,245)	(3,053)
Total	4,696	2,405	5,337
Interest Charges:			
Interest on long-term debt	129,952	130,352	135,772
Other interest - net	6,494	6,605	5,591
Allowance for borrowed funds used during construction	(2,469)	(1,748)	(735)
Total	133,977	135,209	140,628
Net Income	213,839	188,808	182,989
Preferred Stock Dividend Requirements and Other	23,319	24,754	28,416
Earnings Applicable to Common Stock	$190,520	$164,054	$154,573

See Notes to Financial Statements

LOUISIANA POWER & LIGHT COMPANY
STATEMENTS OF RETAINED EARNINGS

	For the Years Ended December 31,		
	1994	1993	1992
		(In Thousands)	
Retained Earnings, January 1	$89,849	$94,510	$117,820
Add:			
Net income	213,839	188,808	182,989
Total	303,688	283,318	300,809
Deduct:			
Dividends declared:			
Preferred stock	22,359	24,553	28,416
Common stock	167,100	167,600	174,600
Capital stock expenses	809	1,316	3,283
Total	190,268	193,469	206,299
Retained Earnings, December 31 (Note 7)	$113,420	$89,849	$94,510

See Notes to Financial Statements.

Net Income

Net income increased in 1994 due primarily to the fourth quarter write-off of the unamortized balances of deferred investment tax credits pursuant to the FERC settlement as discussed in Litigation and Regulatory Proceedings below, partially offset by lower electric operating revenues and higher other operation and maintenance expenses. Net income increased in 1993 due primarily to increased retail energy sales partially offset by the effects of implementing SFAS 109 and SFAS 106.

Significant factors affecting the results of operations and causing variances between the years 1994 and 1993, and 1993 and 1992, are discussed under "Revenues and Sales" and "Expenses" below.

Revenues and Sales

See "Selected Financial Data - Five-Year Comparison," following the notes, for information on operating revenues by source and KWH sales.

Operating revenues were lower in 1994 due primarily to the completion of the amortization of the proceeds resulting from litigation with a gas supplier in the second quarter and lower wholesale revenues partially offset by higher retail revenues. Wholesale revenues decreased due primarily to lower sales to non-associated utilities. Retail revenues increased due primarily to increases in sales to industrial and commercial customers.

Operating revenues were higher in 1993 due primarily to increased residential and commercial energy sales resulting primarily from a return to more normal weather as compared to milder weather in 1992. Industrial energy sales also increased primarily in the petrochemical industry.

Expenses

Operating expenses decreased in 1994 due primarily to a decrease in income tax expense as a result of the write-off of the unamortized balances of deferred investment tax credits pursuant to a FERC settlement and lower fuel expense partially offset by higher other operation and maintenance expense. The decrease in fuel for electric generation and fuel-related expenses and purchased power expense is due primarily to lower fuel and purchased power prices. The increase in other operation and maintenance expense is due primarily to restructuring costs as discussed in Note 12 and power plant waste water site closures as discussed in Note 8.

Operating expenses increased in 1993 due primarily to an increase in fuel expense because of increased generation requirements resulting primarily from increased retail energy sales and higher fuel costs. Total income taxes increased in 1993 due primarily to higher pretax income, an increase in the federal income tax rate as a result of OBRA, and the effect of implementing SFAS 109.

Interest expense decreased in 1994 and 1993 as a result of the refinancing of high cost debt during 1993 and 1992.

Competition

The electric utility industry is becoming increasingly competitive and LP&L is seeking to become a leading competitor in the changing electric energy business. Competition presents LP&L with many challenges. The following have been identified by LP&L as its major competitive challenges.

Retail and Wholesale Rate Issues

Increasing competition in the utility industry brings an increased need to stabilize or reduce retail rates. The retail regulatory philosophy is shifting in some jurisdictions from traditional cost of service regulation to incentive rate regulation. Incentive and performance-based rate plans encourage efficiencies and productivity while permitting utilities and their customers to share in the results. In August 1994, LP&L filed a performance-based formula rate plan with the LPSC. The proposed formula rate plan would continue existing LP&L rates at current levels, while providing financial incentive to reduce costs and maintain high levels of customer satisfaction and system reliability. Hearings were held in March 1995. See Note 2 for additional information. Recognizing that many industrial customers have energy alternatives, LP&L continues to work with these customers to address their needs. In certain cases, competitive prices are negotiated, using variable rate design.

Retail wheeling, the transmission by an electric utility of energy produced by another entity over the utility's transmission and distribution system to a retail customer in the electric utility's area of service, is also evolving. Over a dozen states have been or are studying the concept of retail competition. In April 1994, the state of Michigan initiated a five-year experiment that allows limited competition among public utilities. During the same month, the California Public Utilities Commission proposed to deregulate that state's electric power industry, starting on January 1, 1996, to allow the largest industrial customers to select the lowest cost supplier for electricity service. Under the proposal, by the year 2002, smaller companies and residential customers in California would also be able to buy power from any suppliers. The California Public Utilities Commission is currently reviewing its proposal and is expected to make a ruling in the first half of 1995. The retail market for electricity is expected to become more competitive with such moves toward deregulation.

In some areas of the country, municipalities (or comparable entities) whose residents are served at retail by an investor-owned utility pursuant to a franchise are exploring the possibility of establishing new or extending existing distribution systems or seeking new delivery points in order to serve retail customers, especially large industrial customers, that currently receive service from an investor-owned utility. These options depend on the terms of a utility's franchise as well as on state law and regulation. In addition, FERC's authority to order utilities to transmit for a new or expanding municipal system is limited in certain respects. Where successful, however, the establishment of a municipal system or the acquisition by a municipal system of a utility's customers could result in the inability to recover costs that the utility has incurred in serving those customers.

In mid-1994, the FERC issued a notice of proposed rulemaking concerning a regulatory framework for dealing with recovery of stranded costs, such as high cost nuclear generating units, which may be incurred by electric utilities as a result of increased competition. In addition to addressing recovery of stranded costs related to wholesale service, the proposal requested comment as to recovery of retail stranded costs in transmission rates where state regulatory authorities failed to address the issue or were in conflict. Comments and reply comments have been filed, and the matter is pending. The risk of exposure to stranded costs which may result from competition in the industry will depend on the extent and timing of retail competition, the resolution of jurisdictional issues concerning stranded cost recovery, and the extent to which such costs are recovered from departing or remaining customers, among other matters.

In the wholesale rate area, FERC approved in 1992, with certain modifications, the proposal of AP&L, LP&L, MP&L, NOPSI, and Entergy Power to sell wholesale power at market-based rates and to provide to electric utilities "open access" to the System's transmission system (subject to certain requirements). GSU was later added to this filing. On October 31, 1994, as amended on January 25, 1995, Entergy Services filed with FERC revised transmission tariffs intended to provide access to transmission service on the same or comparable basis, terms, and conditions as the System operating companies, and the matter is pending. Open access and market pricing, once in effect, will increase marketing opportunities for LP&L, but will also expose LP&L to the risk of loss of load or reduced revenues due to competition with alternative suppliers.

In light of the rate issues discussed above, LP&L is aggressively reducing costs to avoid potential earnings erosions that might result as well as to become more competitive. In 1994, LP&L announced a restructuring program related to certain of its operating units. This program is designed to reduce costs and improve operating efficiencies. See Note 12 for further information. Also, in response to an increasingly competitive environment, LP&L announced intentions to revise its initial least cost planning activities.

The Energy Policy Act of 1992

The EPAct addresses a wide range of energy issues and is altering the way Entergy and the rest of the electric utility industry operate. The EPAct encourages competition and affords utilities the opportunities, and the risks, associated with an open and more competitive market environment. The EPAct creates exemptions from regulation under the Holding Company Act and creates a class of exempt wholesale generators consisting of utility affiliates and nonutilities that are owners and operators of facilities for the generation and transmission of power for sales at wholesale. The EPAct also gives FERC the authority to order investor-owned utilities, including LP&L, to transmit power and energy to or for wholesale purchasers and sellers. The law creates the potential for electric utilities and other power producers to gain increased access to the transmission systems of other entities to facilitate wholesale sales. Both LP&L and Entergy Power expect to compete in this market.

Litigation and Regulatory Proceedings

In November 1994, FERC approved an agreement settling a long-standing dispute involving income tax allocation procedures of System Energy. In accordance with the agreement, System Energy refunded approximately $8.6 million to LP&L, which will make refunds or credits to its customers (except for those portions attributable to its retained share of Grand Gulf 1 costs). Additionally, System Energy will refund a total of approximately $8.7 million, plus interest, to LP&L over the period through June 2004. The settlement also required the write-off of approximately $31.5 million of certain related unamortized balances of deferred investment tax credits by LP&L.

Property Tax Exemptions

Exemption from the payment of Louisiana local property taxes on Waterford 3 , which has been in effect for 10 years, will expire in December 1995. LP&L is working with Louisiana local taxing authorities to determine the method for calculating the amount of the property taxes to be paid when the exemption expires. LP&L believes that assessed property taxes will be recovered from its customers through rates.

Environmental Issues

During 1993, the Louisiana Department of Environmental Quality issued new rules for solid waste regulation, including waste water impoundments. LP&L has determined that certain of its power plant waste water impoundments are affected by these regulations and has chosen to either upgrade or close them. The aggregate cost of the upgrades and closures, to be completed by 1996, is estimated to be $16 million.

Accounting Issues

Proposed Accounting Standards - The FASB has proposed a SFAS on "Accounting for the Impairment of Long-Lived Assets," effective January 1, 1996. The proposed standard describes circumstances which may result in assets being impaired and provides criteria for recognition and measurement of asset impairment. Certain operations of LP&L are potentially affected by this standard, and any resulting write-offs will depend on future operating costs, generating units' efficiency and availability, and the future market for energy over the remaining life of the units. Based on current estimates, LP&L anticipates that future revenues will fully recover the costs of such operations.

Continued Application of SFAS 71 - LP&L's financial statements currently reflect assets and costs based on current cost-based ratemaking regulations, in accordance with SFAS 71, "Accounting for the Effects of Certain Types of Regulation." As discussed above, the electric utility industry is changing and these changes could possibly result in the discontinuance of the application of SFAS 71, which would result in the elimination of regulatory assets and liabilities. See Note 1 for further information.

Accounting for Decommissioning Costs - The FASB is currently reviewing the accounting for decommissioning of nuclear plants. This project could possibly change the System's, as well as the entire utility industry's, accounting for such costs. For further information, see Note 8.

NOTE 1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

LP&L maintains accounts in accordance with FERC and other regulatory guidelines. Certain previously reported amounts have been reclassified to conform to current classifications.

Revenues and Fuel Costs

LP&L records revenues when billed to its customers and, in addition, accrues revenue for the nonfuel portion of estimated revenues for energy delivered since the latest billings.

LP&L's rate schedules include fuel adjustment clauses that allow deferral of fuel costs until such costs are reflected in the related revenues.

Utility Plant

Utility plant is stated at original cost. Partial disallowances of plant cost ordered by the regulators have been recorded as an adjustment to utility plant. The original cost of utility plant retired or removed, plus the applicable removal costs, less salvage, is charged to accumulated depreciation. Maintenance, repairs, and minor replacement costs are charged to operating expenses. Substantially all of LP&L's utility plant is subject to the lien of its first mortgage indenture. In addition, certain assets of LP&L are subject to the liens of second mortgages related to pollution control revenue bonds.

Utility plant includes the portions of Waterford 3 that were sold and are currently under lease. LP&L retired this property from its continuing property records as formerly owned property released from and no longer subject to LP&L's first mortgage indenture. LP&L is reflecting such leased property for financial reporting purposes as property under lease from others and depreciating this property over the life of the plant. See Note 9 for additional lease disclosure.

Total LP&L net utility plant in service of $3.41 billion as of December 31, 1994 includes $2.36 billion of production plant, $.24 billion of transmission plant, $.74 billion of distribution plant, and $.07 billion of other plant.

Depreciation is computed on the straight-line basis at rates based on the estimated service lives and costs of removal of the various classes of property. Depreciation provisions on average depreciable property approximated 2.8% in 1994, 3.0% in 1993, and 2.9% in 1992.

AFUDC represents the approximate net composite interest cost of borrowed funds and a reasonable return on the equity funds used for construction. Although AFUDC increases utility plant and increases earnings, it is only realized in cash through depreciation provisions included in rates. LP&L's effective composite rates for AFUDC were 10.1%, 10.4%, and 10.7%, for 1994, 1993, and 1992, respectively.

Income Taxes

LP&L, its parent, and affiliates file a consolidated federal income tax return. Income taxes are allocated to LP&L in proportion to its contribution to consolidated taxable income. SEC regulations require that no Entergy Corporation subsidiary pay more taxes than it would have had a separate income tax return been filed. Deferred

taxes are recorded for all temporary differences between book and taxable income. Investment tax credits are deferred and amortized based upon the average useful life of the related property in accordance with rate treatment. As discussed in Note 3, in 1993 LP&L changed its accounting for income taxes to conform with SFAS 109.

Reacquired Debt

The premiums and costs associated with reacquired debt are being amortized over the life of the related new issuances, in accordance with ratemaking treatment.

Cash and Cash Equivalents

LP&L considers all unrestricted highly liquid debt instruments purchased with an original maturity of three months or less to be cash equivalents.

Continued Application of SFAS 71

As a result of the EPAct and actions of regulatory commissions, the electric utility industry is moving toward a combination of competition and a modified regulatory environment. LP&L's financial statements currently reflect assets and costs based on current cost-based ratemaking regulations in accordance with SFAS 71, "Accounting for the Effects of Certain Types of Regulation." Continued applicability of SFAS 71 to LP&L's financial statements requires that rates set by an independent regulator on a cost of service basis (including a reasonable rate of return on invested capital) can actually be charged to and collected from customers.

In the event that either all or a portion of a utility's operations cease to meet those criteria for various reasons, including deregulation, a change in the method of regulation or a change in the competitive environment for the utility's regulated services, the utility should discontinue application of SFAS 71 for the relevant portion. That discontinuation should be reported by elimination from the balance sheet of the effects of any actions of regulators recorded as regulatory assets and liabilities.

As of December 31, 1994, and for the foreseeable future, LP&L's financial statements continue to follow SFAS 71.

Fair Value Disclosure

The estimated fair value of financial instruments has been determined by LP&L, using available market information and appropriate valuation methodologies. However, considerable judgment is required in developing the estimates of fair value. Therefore, estimates are not necessarily indicative of the amounts that LP&L could realize in a current market exchange. In addition, gains or losses realized on financial instruments may be reflected in future rates and not accrue to the benefit of stockholders.

LP&L considers the carrying amounts of financial instruments classified as current assets and liabilities to be a reasonable estimate of their fair value because of the short maturity of these instruments. In addition, LP&L does not presently expect that performance of its obligations will be required in connection with certain off-balance sheet commitments and guarantees considered financial instruments. Due to this factor, and because of the related party nature of these commitments and guarantees, determination of fair value is not considered practicable. See Notes 5, 6, and 8 for additional fair value disclosure.

LP&L adopted the provisions of SFAS 115, "Accounting for Certain Investments in Debt and Equity Securities," effective January 1, 1994. As a result, at December 31, 1994, LP&L recorded on the balance sheet a reduction of $1.1 million in decommissioning trust funds, representing the amount by which the fair value of the securities held in such funds is less than amounts recovered in rates for decommissioning and deposited in the funds and the related earnings on the amounts deposited. Due to the regulatory treatment for decommissioning trust funds, LP&L recorded an offsetting amount in unrealized losses on investment securities as a regulatory asset.

NOTE 2. RATE AND REGULATORY MATTERS

LPSC Rate Review

In August 1994, LP&L filed a performance-based formula rate plan with the LPSC. The proposed formula rate plan would continue existing LP&L rates at current levels, while providing financial incentive to reduce costs and maintain high levels of customer satisfaction and system reliability. A performance rating adjustment feature of the plan would allow LP&L the opportunity to earn a higher rate of return if it improves performance over time. Conversely, if performance declines, the rate of return LP&L could earn would be lowered. This provides financial incentive for LP&L to maintain continuous improvement in all three performance categories (customer price, customer satisfaction, and customer reliability). Under the proposed plan, if LP&L's earnings fall within a bandwidth around a benchmark rate of return, there would be no adjustment in rates. If LP&L's earnings are above the bandwidth, the proposed plan would automatically reduce LP&L's base rates. Alternatively, if LP&L's earnings are below the bandwidth, the proposed plan would automatically increase LP&L's base rates. The reduction or increase in base rates would be an amount representing 50% of the difference between the earned rate of return and the nearest limit of the bandwidth. In no event would the annual adjustment in rates exceed 2% of LP&L's retail revenues. Hearings were held in March 1995. No assurance can be given that the LPSC will accept the performance-based formula rate plan, or that the current rate review will not result in a rate decrease.

Waterford 3 and Grand Gulf 1

In a series of LPSC orders, court decisions, and agreements between November 1985 and June 1988, LP&L was granted Waterford 3 and Grand Gulf 1 rate relief. In addition, LP&L, in accordance with judicial decisions and LPSC rate orders, deferred a net amount of $266 million of its Waterford 3 costs related to the period November 14, 1985 through January 31, 1988. These deferred costs are being recovered over approximately 8.6 years beginning in April 1988.

In November 1985, LP&L agreed to permanently absorb, and not recover from its retail customers, 18% of its 14% (approximately 2.52%) FERC-allocated share of the costs of capacity and energy of Grand Gulf 1. LP&L is allowed to recover through the fuel adjustment clause 4.6 cents per KWH (as of May 1994) for the energy related to its retained portion of these costs. Alternatively, LP&L may sell such energy to nonaffiliated parties at prices above the fuel adjustment clause recovery amount, subject to LPSC approval. For the year ended December 31, 1994, $66 million was billed to LP&L by System Energy.

NOTE 3. INCOME TAXES

Income tax expense consisted of the following:

	For the Years Ended December 31,		
	1994	1993	1992
		(In Thousands)	
Current:			
Federal	$ 68,891	$ 62,037	$30,326
State	10,369	8,514	6,139
Total	79,260	70,551	36,465
Deferred - net:			
Liberalized depreciation	55,083	54,297	53,751
Unbilled revenue	2,081	3,474	(7,906)
Deferred Waterford 3 expenses	(14,043)	(14,043)	(14,043)
Adjustment of prior years' tax provisions	2,447	2,665	(5,331)
Waterford 3 sale and leaseback	(3,571)	(3,632)	(3,526)
Gas contract settlement	5,483	9,513	15,180
Nuclear refueling and maintenance	3,407	(5,768)	1,989
Materials and supplies inventory adjustments	(2,446)	(2,505)	(2,497)
Alternative minimum tax	(14,604)	(8,781)	-
Property insurance reserve	521	23	3,119
Deferred fuel	(5,148)	(1,337)	2,977
Bond reacquisition	(1,502)	(243)	4,868
Decontamination and decommissioning fund	573	5,273	-
Environmental reserve	(5,832)	213	-
Other	(869)	3,868	3,308
Total	21,580	43,017	51,889
Investment tax credit adjustments - net	(6,048)	(2,755)	(1,317)
Investment tax credit amortization - FERC settlement	(31,504)	-	-
Recorded income tax expense	$ 63,288	$110,813	$87,037
Charged to operations	$ 63,751	$108,568	$83,984
Charged to other income	(463)	2,245	3,053
Recorded income tax expense	63,288	110,813	87,037
Income taxes applied against the debt component of AFUDC	-	-	442
Total income taxes	$ 63,288	$110,813	$87,479

Total income taxes differ from the amounts computed by applying the statutory federal income tax rate to income before taxes. The reasons for the differences were:

	For the Years Ended December 31,					
	1994		1993		1992	
	Amount	% of Pretax Income	Amount	% of Pretax Income	Amount	% of Pretax Income
	(Dollars in Thousands)					
Computed at statutory rate	$ 96,994	35.0	$104,867	35.0	$91,809	34.0
Increases (reductions) in tax resulting from:						
State income taxes net of federal income tax effect	5,147	1.9	6,727	2.2	4,272	1.6
Depreciation	3,219	1.2	2,550	0.9	3,064	1.1
Impact of change in tax rate	(2,749)	(1.0)	(2,767)	(0.9)	(3,989)	(1.5)
Amortization of investment tax credits	(6,305)	(2.3)	(6,876)	(2.3)	(6,780)	(2.5)
Investment tax credit amortization - FERC settlement	(31,504)	(11.3)	-	-	-	-
SFAS 109 adjustment	-	-	4,193	1.4	-	-
Other - net	(1,514)	(0.6)	2,119	0.7	(1,339)	(0.5)
Recorded income tax expense	$ 63,288	22.9	$110,813	37.0	$87,037	32.2
Income taxes applied against the debt component of AFUDC	-	-	-	-	442	0.2
Total income taxes	$ 63,288	22.9	$110,813	37.0	$87,479	32.4

Significant components of LP&L's net deferred tax liabilities as of December 31, 1994 and 1993, were (in thousands):

	1994	1993
Deferred tax liabilities:		
Net regulatory assets	$ (437,468)	$ (422,371)
Plant related basis differences	(722,653)	(665,517)
Rate deferrals	(26,695)	(40,737)
Bond reacquisition loss	(15,866)	(17,368)
Other	(17,106)	(14,429)
Total	$(1,219,788)	$(1,160,422)
Deferred tax assets:		
Unbilled revenues	$ 11,108	$ 13,190
Accumulated deferred investment tax credit	58,205	72,667
Gas contract settlement	7,539	12,917
Removal cost	52,576	47,603
Alternative minimum tax credit	56,222	41,618
Standard coal plant	12,561	12,898
Waterford 3 sale/leaseback	102,111	98,541
Environmental reserve	6,308	476
Other	32,915	31,644
Total	$ 339,545	$ 331,554
Net deferred tax liabilities	$ (880,243)	$ (828,868)

The alternative minimum tax (AMT) credit as of December 31, 1994, was $56.2 million. This AMT credit can be carried forward indefinitely and will reduce LP&L's federal income tax liability in future years.

In accordance with a System Energy FERC settlement, LP&L wrote off $31.5 million of unamortized deferred investment tax credits in 1994.

In 1993, LP&L adopted SFAS 109. SFAS 109 required that deferred income taxes be recorded for all temporary differences and carryforwards, and that deferred tax balances be based on enacted tax laws at tax rates that are expected to be in effect when the temporary differences reverse. SFAS 109 required that regulated enterprises recognize adjustments resulting from implementation as regulatory assets or liabilities if it is probable that such amounts will be recovered from or returned to customers in future rates. A substantial majority of the adjustments required by SFAS 109 was recorded to deferred tax balance sheet accounts with offsetting adjustments to regulatory assets and liabilities. As a result of the adoption of SFAS 109, 1993 net income was reduced by $5.7 million, assets were increased by $309.7 million, and liabilities were increased by $315.4 million. The cumulative effect of the adoption of SFAS 109 is included in income tax expense charged to operations.

In August 1994, Entergy received an Internal Revenue Service report covering the federal income tax audit of Entergy Corporation and subsidiaries for the years 1988 - 1990. The report asserts an $80 million tax deficiency for the 1990 consolidated federal income tax returns related primarily to the application of accelerated investment tax credits associated with Waterford 3 and Grand Gulf nuclear plants. Entergy believes there is no material tax deficiency and is vigorously contesting the proposed assessment.

NOTE 4. LINES OF CREDIT AND RELATED BORROWINGS

The SEC has authorized LP&L to effect short-term borrowings up to $150 million, which may be increased to as much as $236 million after further SEC approval. This authorization is effective through November 30, 1996. As of December 31, 1994, LP&L had outstanding short-term lines of credit of $19.2 million from banks within its service territory. Interest rates associated with these lines of credit generally are based on the prime rate, the London interbank offered rate, or a bid rate. Commitment fees on these lines of credit are .125% of the amount of available credit. In addition, LP&L can borrow from the Money Pool, subject to its maximum authorized level of short-term borrowings and the availability of funds. LP&L had $8 million of outstanding borrowings under the Money Pool arrangement as of December 31, 1994.

NOTE 5. PREFERRED STOCK

The number of shares and dollar value of LP&L's preferred stock were:

	As of December 31,				
	Shares Authorized and Outstanding		Total Dollar Value		Call Price Per Share as of December 31,
	1994	1993	1994	1993	1994
			(Dollars in Thousands)		
Without sinking fund:					
Cumulative, $100 par value					
4.96% Series	60,000	60,000	$ 6,000	$ 6,000	$104.25
4.16% Series	70,000	70,000	7,000	7,000	$104.21
4.44% Series	70,000	70,000	7,000	7,000	$104.06
5.16% Series	75,000	75,000	7,500	7,500	$104.18
5.40% Series	80,000	80,000	8,000	8,000	$103.00
6.44% Series	80,000	80,000	8,000	8,000	$102.92
7.84% Series	100,000	100,000	10,000	10,000	$103.78
7.36% Series	100,000	100,000	10,000	10,000	$103.36
8.56% Series	100,000	100,000	10,000	10,000	$103.14
Cumulative, $25 par value					
8.00% Series (1)	1,480,000	1,480,000	37,000	37,000	-
9.68% Series (1)	2,000,000	2,000,000	50,000	50,000	-
Total without sinking fund	4,215,000	4,215,000	$160,500	$160,500	
With sinking fund:					
Cumulative, $100 par value					
7.00% Series (1)	500,000	500,000	$ 50,000	$ 50,000	-
8.00% Series (1)	350,000	350,000	35,000	35,000	-
Cumulative, $25 par value					
10.72% Series	150,211	390,211	3,756	9,755	$25.67
13.12% Series	-	61,121	-	1,528	-
14.72% Series	-	416	-	10	-
12.64% Series	900,370	1,200,370	22,509	30,009	$27.37
Total with sinking fund	1,900,581	2,502,118	$111,265	$126,302	

(1) These series are not redeemable as of December 31, 1994.

The fair value of LP&L's preferred stock with sinking fund was estimated to be approximately $113.0 million and $141.9 million as of December 31, 1994 and 1993, respectively. The fair values were determined using quoted market prices or estimates from nationally recognized investment banking firms. See Note 1 for additional information on disclosure of fair value of financial instruments.

Changes in preferred stock, with and without sinking fund, during the last three years were:

	Number of Shares		
	1994	1993	1992
Preferred stock issuances:			
$100 par value	-	-	500,000
$25 par value	-	-	1,480,000
Preferred stock retirements:			
$100 par value	-	-	(370,000)
$25 par value	(601,537)	(900,000)	(1,015,160)

Cash sinking fund requirements for the next five years for preferred stock outstanding as of December 31, 1994 are (in millions): 1995 - $6.8; 1996 - $4.5; 1997 - $3.8; 1998 - $3.8; and 1999 - $53.8. LP&L has the annual non-cumulative option to redeem, at par, additional amounts of certain series of its outstanding preferred stock.

NOTE 6. LONG-TERM DEBT

LP&L's long-term debt as of December 31, 1994 and 1993, was:

Maturities		Interest Rates			
From	To	From	To	1994	1993
				(In Thousands)	
First Mortgage Bonds					
1995	1999	5-5/8%	10.36%	$ 179,000	$ 204,000
2000	2004	6%	8%	361,520	361,520
2020	2022	8-1/2%	10-1/8%	185,000	185,000
Governmental Obligations*					
1994	2009	6-2/5%	8%	40,472	37,794
2010	2023	5.95%	8-1/4%	367,400	350,000
Waterford 3 Lease Obligation, 8.76% (Note 9)				353,600	353,600
Unamortized Premium and Discount - Net				(8,617)	(8,973)
Total Long-Term Debt				1,478,375	1,482,941
Less Amount Due Within One Year				75,320	25,315
Long-Term Debt Excluding Amount Due Within One Year				$1,403,055	$1,457,626

* Consists of pollution control bonds, certain series of which are secured by non-interest bearing first mortgage bonds.

The fair value of LP&L's long-term debt, excluding Waterford 3 lease obligation and long-term Purchase Agreement, as of December 31, 1994 and 1993 was estimated to be $1,089.2 million and $1,205.1 million, respectively. The fair values were determined using quoted market prices or estimates from nationally recognized investment banking firms. See Note 1 for additional information on disclosure of fair value of financial instruments.

For the years 1995, 1996, 1997, 1998, and 1999, LP&L has long-term debt maturities and cash sinking fund requirements of (in millions): $75.3, $35.3, $34.3, $35.3 and $0.2, respectively. In addition, other sinking fund requirements of approximately $5.9 million annually may be satisfied by cash or by certification of property additions at the rate of 167% of such requirements.

NOTE 7. DIVIDEND RESTRICTIONS

LP&L's Restated Articles of Incorporation, as amended, and certain of its indentures, contain provisions restricting the payment of cash dividends or other distributions on common stock. As of December 31, 1994, none of LP&L's retained earnings were restricted against the payment of cash dividends or other distributions on common stock. On February 1, 1995, LP&L paid Entergy Corporation a $55.7 million cash dividend on common stock.

NOTE 8. COMMITMENTS AND CONTINGENCIES

Capital Requirements and Financing

Construction expenditures (excluding nuclear fuel) for the years 1995, 1996, and 1997 are estimated to total $115.4 million each year. LP&L will also require $160 million during the period 1995-1997 to meet long-term debt and preferred stock maturities and cash sinking fund requirements. LP&L plans to meet the above requirements with internally generated funds and cash on hand, supplemented by the issuance of debt. See Notes 5 and 6 regarding the possible refunding, redemption, purchase or other acquisition of certain outstanding series of preferred stock and long-term debt.

Unit Power Sales Agreement

System Energy has agreed to sell all of its 90% owned and leased share of capacity and energy from Grand Gulf 1 to AP&L, LP&L, MP&L, and NOPSI in accordance with specified percentages (AP&L 36%, LP&L 14%, MP&L 33%, and NOPSI 17%) as ordered by FERC. Charges under this agreement are paid in consideration for LP&L's respective entitlement to receive capacity and energy, and are payable irrespective of the quantity of energy delivered so long as the unit remains in commercial operation. The agreement will remain in effect until terminated by the parties and approved by FERC, most likely upon Grand Gulf 1's retirement from service. LP&L's monthly obligation for payments under the agreement is approximately $7 million.

Availability Agreement

AP&L, LP&L, MP&L, and NOPSI are individually obligated to make payments or subordinated advances to System Energy in accordance with stated percentages (AP&L 17.1%, LP&L 26.9%, MP&L 31.3%, and NOPSI 24.7%) in amounts that when added to amounts received under the Unit Power Sales Agreement or otherwise, are adequate to cover all of System Energy's operating expenses. System Energy has assigned its rights to payments and advances to certain creditors as security for certain obligations. Since commercial operation of Grand Gulf 1, payments under the Unit Power Sales Agreement have exceeded the amounts payable under the Availability Agreement. Accordingly, no payments have ever been required. If AP&L, MP&L, or NOPSI fails to make its Unit Power Sales Agreement payments, and System Energy is unable to obtain funds from other sources, LP&L could be liable for payments to System Energy, in amounts that cannot be determined, over and above its payments under the Unit Power Sales Agreement.

Reallocation Agreement

System Energy and AP&L, LP&L, MP&L, and NOPSI entered into the Reallocation Agreement relating to the sale of capacity and energy from the Grand Gulf Station and the related costs, in which LP&L, MP&L, and NOPSI agreed to assume all of AP&L's responsibilities and obligations with respect to the Grand Gulf Station under the Availability Agreement. FERC's decision allocating a portion of Grand Gulf 1 capacity and energy to AP&L supersedes the Reallocation Agreement as it relates to Grand Gulf 1. Responsibility for any Grand Gulf 2 amortization amounts has been individually allocated (LP&L 26.23%, MP&L 43.97%, and NOPSI 29.80%) under the terms of the Reallocation Agreement. However, the Reallocation Agreement does not affect AP&L's obligation to System Energy's lenders under the assignments referred to in the preceding paragraph. AP&L would be liable for its share of such amounts if LP&L, MP&L, and NOPSI were unable to meet their contractual obligations. No payments of any amortization amounts will be required as long as amounts paid to System Energy under the Unit Power Sales Agreement, including other funds available to System Energy, exceed amounts required under the Availability Agreement, which is expected to be the case for the foreseeable future.

System Fuels

LP&L has a 33% interest in System Fuels, a jointly owned subsidiary of AP&L, LP&L, MP&L, and NOPSI. The parent companies of System Fuels, including LP&L, agreed to make loans to System Fuels to finance its fuel procurement, delivery, and storage activities. As of December 31, 1994, LP&L had approximately $14.2 million of loans outstanding to System Fuels which mature in 2008.

In addition, System Fuels entered into a revolving credit agreement with a bank that provides $45 million in borrowings to finance System Fuels' nuclear materials and services inventory. Should System Fuels default on its obligations under its credit agreement, AP&L, LP&L, and System Energy have agreed to purchase the nuclear materials and services financed under the agreement.

Long-Term Contracts

LP&L has a long-term agreement through the year 2031 to purchase energy generated by a hydroelectric facility. During 1994, 1993, and 1992, LP&L made payments under the contract of approximately $56.3 million, $66.9 million, and $39.1 million, respectively. If the maximum percentage (94%) of the energy is made available to LP&L, current production projections would require estimated payments of approximately $47 million per year through 1996, $54 million in 1997, and a total of $3.5 billion for the years 1998 through 2031. LP&L recovers the costs of purchased energy through its fuel adjustment clause.

In June 1992, LP&L agreed to a renegotiated 20-year natural gas supply contract. LP&L has agreed to purchase natural gas in annual amounts equal to approximately one-third of its projected annual fuel requirements for certain generating units. Annual demand charges associated with this contract are estimated to be $9 million through 1997, and a total of $124 million for the years 1998 through 2012. LP&L recovers the cost of fuel consumed during the generation of electricity through its fuel adjustment clause.

Nuclear Insurance

The Price-Anderson Act limits public liability for a single nuclear incident to approximately $8.92 billion as of December 31, 1994. LP&L has protection for this liability through a combination of private insurance (currently $200 million) and an industry assessment program. Under the assessment program, the maximum

amount that would be required for each nuclear incident would be $79.3 million per reactor, payable at a rate of $10 million per licensed reactor per incident per year. LP&L has one licensed reactor. In addition, LP&L participates in a private insurance program which provides coverage for worker tort claims filed for bodily injury caused by radiation exposure. LP&L's maximum assessment under the program is an aggregate of approximately $3.2 million in the event losses exceed accumulated reserve funds.

LP&L is a member of certain insurance programs that provide coverage for property damage, including decontamination and premature decommissioning expense, to members' nuclear generating plants. As of December 31, 1994, LP&L was insured against such losses up to $2.75 billion, with $250 million of this amount designated to cover any shortfall in the NRC required decommissioning trust funding. In addition, LP&L is a member of an insurance program that covers certain costs of replacement power and business interruption incurred due to prolonged nuclear unit outages. Under the property damage and replacement power/business interruption insurance programs, LP&L could be subject to assessments if losses exceed the accumulated funds available to the insurers. As of December 31, 1994, the maximum amount of such possible assessments to LP&L was $34.7 million.

The amount of property insurance presently carried by LP&L exceeds the Nuclear Regulatory Commission's (NRC) minimum requirement for nuclear power plant licensees of $1.06 billion per site. NRC regulations provide that the proceeds of this insurance must be used, first, to place and maintain the reactor in a safe and stable condition and, second, to complete decontamination operations. Only after proceeds are dedicated for such use and regulatory approval is secured, would any remaining proceeds be made available for the benefit of plant owners or their creditors.

Spent Nuclear Fuel and Decommissioning Costs

LP&L provides for estimated future disposal costs for spent nuclear fuel in accordance with the Nuclear Waste Policy Act of 1982. LP&L entered into a contract with the DOE, whereby the DOE will furnish disposal service at a cost of one mill per net KWH generated and sold. The fees payable to the DOE may be adjusted in the future to assure full recovery. LP&L considers all costs incurred or to be incurred, except accrued interest, for the disposal of spent nuclear fuel to be proper components of nuclear fuel expense, and provisions to recover such costs have been accepted by the LPSC.

Delays have occurred in the DOE's program for the acceptance and disposal of spent nuclear fuel at a permanent repository. In a statement released February 17, 1993, the DOE asserted that it does not have a legal obligation to accept spent nuclear fuel without an operational repository for which it has not yet arranged. Currently the DOE projects it will begin to accept spent fuel no earlier than 2010. In the meantime, LP&L is responsible for spent fuel storage. Current on-site spent fuel storage capacity at Waterford 3 is estimated to be sufficient until 2000. Thereafter, LP&L will provide additional storage capacity at an estimated initial cost of $5.0 million to $10.0 million. In addition, approximately $3.0 million to $5.0 million will be required every four to five years subsequent to 2000 until the DOE's repository begins accepting Waterford 3's spent fuel.

Entergy Operations and System Fuels joined in lawsuits against the DOE, seeking clarification of the DOE's responsibility to receive spent nuclear fuel beginning in 1998. The original suits, filed June 20, 1994, asked for a ruling stating that the Nuclear Waste Policy Act require the DOE to begin taking title to the spent fuel and to start removing it from nuclear power plants in 1998, a mandate for the DOE's nuclear waste management program to begin accepting fuel in 1998 and court monitoring of the program, and the potential for escrow of payments to a nuclear waste fund instead of directly to the DOE.

Decommissioning costs for Waterford 3 were estimated to be $203.0 million (in 1988 dollars), based on a 1988 update to the original cost study. LP&L had LPSC authorization to fund and recover $4.0 million of decommissioning costs annually through 1993, based on the 1988 study update. LP&L has funded at an annual rate of $4.8 million since January 1994, in anticipation of a 1994 study update and a related LPSC review and determination of appropriate funding levels. The updated cost study completed in 1994 (in 1993 dollars) reflected a cost of decommissioning of $320.1 million. LP&L filed the updated cost study with the LPSC and requested a rate adjustment for decommissioning expense, which is being reviewed. The amounts recovered in rates are deposited in an external trust fund and are reported at market value. The accumulated decommissioning liability of $28.2 million as of December 31, 1994 has been recorded in accumulated depreciation. Decommissioning expense in the amount of $4.8 million was recorded in 1994. The actual decommissioning costs may vary from the above estimates because of regulatory requirements, changes in technology, and increased costs of labor, materials, and equipment. Management believes that actual decommissioning costs are likely to be higher than the amounts presented above.

The staff of the SEC has questioned certain of the current accounting practices of the electric utility industry, regarding the recognition, measurement, and classification of decommissioning costs for nuclear generating stations in the financial statements of electric utilities. In response to these questions, FASB is currently reviewing the accounting for decommissioning. If current electric utility industry accounting practices for such decommissioning are changed, annual provisions for decommissioning could increase, the estimated cost for decommissioning could be recorded as a liability rather than as accumulated depreciation, and trust fund income from the external decommissioning trusts could be reported as investment income rather than as a reduction to decommissioning expense.

The EPAct has a provision that assesses domestic nuclear utilities with fees for the decontamination and decommissioning of the DOE's past uranium enrichment operations. The decontamination and decommissioning assessments will be used to set up a fund into which contributions from utilities and the federal government will be placed. LP&L's annual assessment, which will be adjusted annually for inflation, is $1.3 million (in 1995 dollars) for approximately 15 years. FERC requires that utilities treat these assessments as costs of fuel as they are amortized. The cumulative liability of $14.5 million at December 31, 1994 is recorded in other current liabilities and other noncurrent liabilities, according to FERC guidelines, and is offset in the financial statements by a regulatory asset.

Sales/Use Tax Issues

In September 1994, the Louisiana Supreme Court (Court) issued an opinion (in a case in which none of the System companies was a party) holding, in part, that the Louisiana state legislature's suspension of state sales and use tax exemptions also had the effect of suspending exemptions from local sales and use taxes. On January 27, 1995 the Court, after rehearing, reversed its opinion. Because of the Court's most recent ruling, sales of electricity and gas, fuels and other items used by LP&L to generate electricity in Louisiana, as well as other items exempt from sales and use taxes, continue to be exempt from local sales and use taxes, even though the state exemptions for sales and use tax have been suspended.

Environmental Issues

During 1993, the Louisiana Department of Environmental Quality issued new rules for solid waste regulation, including waste water impoundments. LP&L has determined that certain of its power plant waste water impoundments are affected by these regulations and has chosen to either upgrade or close them. The aggregate cost of the upgrades and closures, to be completed by 1996, is estimated to be $16 million.

NOTE 9. LEASES

General

As of December 31, 1994, LP&L had noncancelable operating leases with minimum lease payments as follows (in thousands):

1995	$ 4,395
1996	4,038
1997	3,924
1998	3,811
1999	3,505
Years thereafter	3,413
Minimum lease payments	$ 23,086

Rental expense for operating leases amounted to approximately $12.1 million, $6.6 million, and $8.7 million in 1994, 1993, and 1992, respectively.

Nuclear Fuel Lease

LP&L has an arrangement to lease nuclear fuel in an amount up to $95 million. The lessor finances its acquisition of nuclear fuel through a credit agreement and the issuance of notes. The credit agreement, which was entered into in 1989, has been extended to January 1998, and the notes have varying remaining maturities of up to 4 years. It is expected that the credit arrangement will be extended or alternative financing will be secured by the lessor upon the maturity of the current arrangements. If the lessor cannot arrange for alternative financing upon maturity of its borrowings, LP&L must purchase nuclear fuel in an amount sufficient to enable the lessor to retire such borrowings.

Lease payments are based on nuclear fuel use. Nuclear fuel lease expense of $32.2 million, $39.9 million, and $38.3 million (including interest of $4.3 million, $4.9 million, and $5.4 million) was charged to operations in 1994, 1993, and 1992, respectively.

Waterford 3 Lease Obligations

On September 28, 1989, LP&L entered into three substantially identical, but entirely separate, transactions for the sale (for an aggregate cash consideration of $353.6 million) and leaseback of three undivided portions of its 100% ownership interest in Waterford 3. The three undivided interests in Waterford 3 sold and leased back exclude certain transmission, pollution control, and other facilities that are part of Waterford 3. The interests sold and leased back, as described above, are equivalent on an aggregate cost basis to approximately 9.3% of Waterford 3. The sales were made to an Owner Trustee under three separate, but identical, trust agreements with three Owner Participants. LP&L is leasing back the sold interests from the Owner Trustee on a net lease basis over an approximate 28-year basic lease term. LP&L has options to terminate the lease and to repurchase the sold interests in Waterford 3 at certain intervals during the basic lease term. Further, at the end of the basic lease term, LP&L has an option to renew the lease or to repurchase the undivided interests in Waterford 3.

The Owner Trustee acquired the interests with funds provided by the Owner Participants and with funds obtained from the issuance and sale by the Owner Trustee of intermediate-term and long-term bonds. The lease payments to be made by LP&L will be sufficient to service the debt incurred by the Owner Trustee.

LP&L did not exercise its option to repurchase the undivided interests in Waterford 3 on the fifth anniversary (September 1994) of the closing date of the sale and leaseback transactions. As a result, LP&L was required to provide collateral to the Owner Participants for the equity portion of certain amounts payable by LP&L under the lease. Such collateral was in the form of a new series of non-interest bearing first mortgage bonds in the aggregate principal amount of $208.2 million issued by LP&L in September 1994 under its first mortgage bond indenture.

Upon the occurrence of certain adverse events (including lease events of default, events of loss, deemed loss events or certain adverse "Financial Events" with respect to LP&L), LP&L may be obligated to pay amounts sufficient to permit the Owner Participants to withdraw from the lease transactions and LP&L may be required to assume the outstanding bonds issued by the Owner Trustee to finance its acquisition of the undivided interests in Waterford 3. "Financial Events" include, among other things, failure by LP&L, following the expiration of any applicable grace or cure periods, to maintain (1) as of the end of any fiscal quarter, total equity capital (including preferred stock) at least equal to 30% of adjusted capitalization, or (2) in respect of the 12-month period ending on the last day of any fiscal quarter, a fixed charge coverage ratio of at least 1.50. As of December 31, 1994, LP&L's total equity capital (including preferred stock) was 49.10% of adjusted capitalization and its fixed charge coverage ratio was 3.01.

In accordance with SFAS 98, "Accounting for Leases," due to "continuing involvement" by LP&L, the sale and leaseback by LP&L of the undivided portions of Waterford 3, as described above, are required to be reflected for financial reporting purposes as financing transactions in LP&L's financial statements even though such portions are no longer owned by LP&L. See Note 1 for further information regarding financial reporting treatment.

As of December 31, 1994, LP&L had future minimum lease payments (reflecting an overall implicit rate of 8.76%) in connection with the Waterford 3 sale and leaseback transactions as follows (in thousands):

1995	$ 32,569
1996	35,165
1997	39,805
1998	41,447
1999	50,530
Years thereafter	676,214
Minimum lease payments	$875,730

NOTE 10. POSTRETIREMENT BENEFITS

Pension Plan

LP&L has a defined benefit pension plan covering substantially all of its employees. The pension plan is noncontributory and provides pension benefits based on employees' credited service and average compensation, generally during the last five years before retirement. LP&L funds pension costs in accordance with contribution guidelines established by the Employee Retirement Income Security Act of 1974, as amended, and the Internal

Revenue Code of 1986, as amended. The assets of the plan consist primarily of common and preferred stocks, fixed income securities, interest in a money market fund, and insurance contracts.

LP&L's 1994, 1993, and 1992 pension cost, including amounts capitalized, included the following components:

	For the Years Ended December 31,		
	1994	1993	1992
	(In Thousands)		
Service cost - benefits earned during the period	$ 5,441	$ 4,900	$ 4,307
Interest cost on projected benefit obligation	14,473	14,684	14,110
Actual return on plan assets	2,024	(26,533)	(14,329)
Net amortization and deferral	(19,981)	8,712	(3,113)
Net pension cost	$ 1,957	$ 1,763	$ 975

The funded status of LP&L's pension plan as of December 31, 1994 and 1993, was (excluding amounts allocable to NOPSI):

	1994	1993
	(In Thousands)	
Actuarial present value of accumulated pension plan benefits:		
Vested	$154,927	$179,049
Nonvested	795	768
Accumulated benefit obligation	$155,722	$179,817
Plan assets at fair value	$198,724	$224,203
Projected benefit obligation	178,895	211,928
Plan assets in excess of projected benefit obligation	19,829	12,275
Unrecognized prior service cost	4,881	6,257
Unrecognized transition asset	(19,653)	(22,460)
Unrecognized net gain	(16,677)	(5,734)
	(11,620)	(9,662)
Unfunded portion of NOPSI pension liability	(1,584)	(12,256)
Accrued pension liability	$(13,204)	$(21,918)

The significant actuarial assumptions used in computing the information above for 1994, 1993, and 1992 were as follows: weighted average discount rate, 8.5% for 1994, 7.5% for 1993 and 8.25% for 1992; weighted average rate of increase in future compensation levels, 5.1% for 1994 and 5.6% for 1993 and 1992; and expected long-term rate of return on plan assets, 8.5%. Transition assets are being amortized over 15 years.

Other Postretirement Benefits

LP&L also provides certain health care and life insurance benefits for retired employees. Substantially all employees may become eligible for these benefits if they reach retirement age while still working for LP&L. The cost of providing these benefits, recorded on a cash basis, to retirees in 1992 was approximately $3.7 million.

Effective January 1, 1993, LP&L adopted SFAS 106. This standard required a change from a cash method to an accrual method of accounting for postretirement benefits other than pensions. LP&L continues to

fund these benefits on a pay-as-you-go basis. As of January 1, 1993, the actuarially determined accumulated postretirement benefit obligation (APBO) earned by retirees and active employees was estimated to be approximately $59.4 million. This obligation is being amortized over a 20-year period beginning in 1993.

The LPSC ordered LP&L to use the pay-as-you-go method for ratemaking purposes for postretirement benefits other than pensions, but the LPSC retains the flexibility to examine individual companies' accounting for postretirement benefits to determine if special exceptions to this order are warranted.

LP&L's 1994 and 1993 postretirement benefit cost, including amounts capitalized and deferred, included the following components:

	1994	1993
	(In Thousands)	
Service cost - benefits earned during the period	$ 2,433	$ 2,083
Interest cost on APBO	4,422	4,749
Net amortization and deferral	3,066	2,971
Net periodic postretirement benefit cost	$ 9,921	$ 9,803

The funded status of LP&L's postretirement plan as of December 31, 1994 and 1993, was as follows:

	1994	1993
	(In Thousands)	
Accumulated postretirement benefit obligation:		
Retirees	$ 38,401	$ 41,769
Other fully eligible participants	8,550	6,825
Other active participants	9,695	21,085
	56,646	69,679
Plan assets at fair value	-	-
Plan assets less than APBO	(56,646)	(69,679)
Unrecognized transition obligation	53,488	56,459
Unrecognized net loss (gain)	(8,253)	7,579
Accrued postretirement benefit liability	$ (11,411)	$ (5,641)

The assumed health care cost trend rate used in measuring the APBO was 9.4% for 1995, gradually decreasing each successive year until it reaches 5% in 2011. A one percentage-point increase in the assumed health care cost trend rate for each year would have increased the APBO as of December 31, 1994, by 8.9% and the sum of the service cost and interest cost by approximately 11.4%. The assumed discount rate and rate of increase in future compensation used in determining the APBO were 8.5% for 1994 and 7.5% for 1993 and 5.1% for 1994 and 5.5% for 1993, respectively.

NOTE 11. TRANSACTIONS WITH AFFILIATES

LP&L buys electricity from and/or sells electricity to the other System operating companies and System Energy under rate schedules filed with FERC. In addition, LP&L purchases fuel from System Fuels, receives technical and advisory services from Entergy Services, and receives operating services from Entergy Operations.

Operating revenues include revenues from sales to affiliates amounting to $1.0 million in 1994, $4.8 million in 1993, and $5.5 million in 1992. Operating expenses include charges from affiliates for fuel costs, purchased power and related charges, management services, and technical and advisory services totaling $365.8 million in 1994, $322 million in 1993, and $314.3 million in 1992. LP&L pays directly or reimburses Entergy Operations for the costs associated with operating Waterford 3 (excluding nuclear fuel), which were approximately $152.5 million in 1994, $118.9 million in 1993, and $152.1 million in 1992.

NOTE 12. RESTRUCTURING COSTS

During the third quarter of 1994, LP&L announced a restructuring program related to certain of its operating units. The program is designed to reduce costs, improve operating efficiencies, and increase shareholder value in order to enable LP&L to become a low-cost producer. The program includes reductions in the number of employees and the consolidation of offices and facilities. In 1994, LP&L recorded restructuring charges of $6.8 million. These charges primarily include employee severance costs related to the expected termination of approximately 296 employees. As of December 31, 1994, no employees have been terminated and no termination benefits have been paid under this restructuring program.

NOTE 13. QUARTERLY FINANCIAL DATA (UNAUDITED)

LP&L's business is subject to seasonal fluctuations with the peak period occurring during the third quarter. Operating results for the four quarters of 1994 and 1993 were:

	Operating Revenues	Operating Income	Net Income
		(In Thousands)	
1994:			
First Quarter	$383,826	$ 68,668	$37,096
Second Quarter	$441,643	$ 80,686	$48,353
Third Quarter	$502,458	$ 99,824	$67,029
Fourth Quarter	$380,614	$ 93,942	$61,361
1993:			
First Quarter	$357,856	$ 56,875	$25,733
Second Quarter	$399,570	$ 79,472	$46,932
Third Quarter	$545,487	$124,789	$92,287
Fourth Quarter	$426,753	$ 60,476	$23,856

See "Significant Factors and Known Trends - Litigation and Regulatory Proceedings" for information regarding the write-off of certain unamortized deferred investment tax credits in the fourth quarter of 1994.

LOUISIANA POWER & LIGHT COMPANY

SELECTED FINANCIAL DATA - FIVE-YEAR COMPARISON

	1994	1993	1992	1991	1990
			(In Thousands)		
Operating revenues	$1,708,541	$1,729,666	$1,553,745	$1,528,934	$1,485,572
Net income	$ 213,839	$ 188,808	$ 182,989	$ 166,572	$ 155,049
Total assets	$4,435,439	$4,463,998	$4,109,148	$4,131,751	$4,262,124
Long-term obligations (1)	$1,530,558	$1,611,436	$1,622,909	$1,582,606	$1,867,369

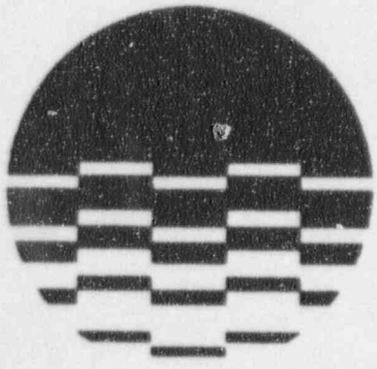
(1) Includes long-term debt (excluding currently maturing debt), preferred stock with sinking fund, and noncurrent capital lease obligations.

See Notes 3 and 10 for the effect of accounting changes in 1993.

	1994	1993	1992	1991	1990
			(Dollars in Thousands)		
Operating Revenues:					
Residential	$ 577,084	$ 572,738	$ 518,255	$ 525,594	$ 520,800
Commercial	358,672	345,254	320,688	318,613	314,700
Industrial	659,061	652,574	578,741	558,036	532,800
Governmental	31,679	29,723	27,780	28,303	26,500
Total retail	1,626,496	1,600,289	1,445,464	1,430,546	1,394,800
Sales for resale	35,406	49,388	38,632	31,997	41,800
Other	46,639	79,989	69,649	66,391	49,000
Total	$1,708,541	$1,729,666	$1,553,745	$1,528,934	$1,485,600
Billed Electric Energy Sales (Millions of KWH):					
Residential	7,449	7,368	6,996	7,182	7,169
Commercial	4,631	4,435	4,307	4,367	4,299
Industrial	16,561	15,914	15,013	14,832	14,170
Governmental	423	398	385	405	382
Total retail	29,064	28,115	26,701	26,786	26,020
Sales for resale	786	1,325	1,305	1,201	1,149
Total	29,850	29,440	28,006	27,987	27,169

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Mississippi Power & Light Company/1994 Financial Statements



MP&L

MISSISSIPPI POWER & LIGHT COMPANY

DEFINITIONS

Certain abbreviations or acronyms used in MP&L's Financial Statements, Notes to Financial Statements, and Management's Financial Discussion and Analysis are defined below:

Abbreviation or Acronym	Term
AFUDC	Allowance for Funds Used During Construction
APL	Arkansas Power & Light Company
Entergy or System	Entergy Corporation and its various direct and indirect subsidiaries
Entergy Services	Entergy Services, Inc.
EPAct	The Energy Policy Act of 1992
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
Final Order on Rehearing	An order issued by the MPSC on September 16, 1985, with respect to MP&L's Grand Gulf 1-related rate issues
G&R Bonds	General and Refunding Mortgage Bonds issued and issuable under MP&L's G&R Mortgage dated as of February 1, 1988, as amended
G&R Mortgage	General and Refunding Mortgage established by MP&L effective February 1, 1988, to provide for issuances of G&R Bonds
Grand Gulf Station	Grand Gulf Steam Electric Generating Station (nuclear)
Grand Gulf 1	Unit No. 1 of the Grand Gulf Station (nuclear)
Grand Gulf 2	Unit No. 2 of the Grand Gulf Station (nuclear)
GSU	Gulf States Utilities Company (including wholly owned subsidiaries - Varibus Corporation, GSG&T, Inc., Prudential Oil and Gas, Inc., and Southern Gulf Railway Company)
Independence Station	Independence Steam Electric Generating Station
KWH	Kilowatt-Hours
LP&L	Louisiana Power & Light Company
MWH	Megawatt-Hours

DEFINITIONS - (Concluded)

Abbreviation or Acronym	Term
Merger	The combination transaction, consummated on December 31, 1993, by which GSU became a subsidiary of Entergy Corporation and Entergy Corporation became a Delaware Corporation
Money Pool	Entergy Money Pool, which allows certain System companies to borrow from, or lend to, certain other System companies
MP&L	Mississippi Power & Light Company
MPSC	Mississippi Public Service Commission
NOPSI	New Orleans Public Service Inc.
OBRA	Omnibus Budget Reconciliation Act of 1993
Revised Plan	MP&L's Grand Gulf 1-related rate phase-in plan, originally approved by the MPSC in the Final Order on Rehearing, as modified by the MPSC order issued September 29, 1988, to bring such plan into compliance with the requirements of SFAS 92
SEC	Securities and Exchange Commission
SFAS	Statement of Financial Accounting Standards promulgated by the FASB
SFAS 106	SFAS 106, "Employers' Accounting for Postretirement Benefits Other Than Pensions"
SFAS 109	SFAS 109, "Accounting for Income Taxes"
System Energy	System Energy Resources, Inc.
System Fuels	System Fuels, Inc.
System or Entergy	Entergy Corporation and its various direct and indirect subsidiaries
System operating companies	AP&L, GSU, LP&L, MP&L, and NOPSI, collectively

MISSISSIPPI POWER & LIGHT COMPANY

REPORT OF MANAGEMENT

The management of Mississippi Power & Light Company has prepared and is responsible for the financial statements and related financial information included herein. The financial statements are based on generally accepted accounting principles. Financial information included elsewhere in this report is consistent with the financial statements.

To meet its responsibilities with respect to financial information, management maintains and enforces a system of internal accounting controls that is designed to provide reasonable assurance, on a cost-effective basis, as to the integrity, objectivity, and reliability of the financial records, and as to the protection of assets. This system includes communication through written policies and procedures, an employee Code of Conduct, and an organizational structure that provides for appropriate division of responsibility and the training of personnel. This system is also tested by a comprehensive internal audit program.

The independent public accountants provide an objective assessment of the degree to which management meets its responsibility for fairness of financial reporting. They regularly evaluate the system of internal accounting controls and perform such tests and other procedures as they deem necessary to reach and express an opinion on the fairness of the financial statements.

Management believes that these policies and procedures provide reasonable assurance that its operations are carried out with a high standard of business conduct.

EDWIN LUPBERGER
Chairman and Chief Executive Officer

GERALD D. MCINVALE
Senior Vice President and
Chief Financial Officer

MISSISSIPPI POWER & LIGHT COMPANY

AUDIT COMMITTEE CHAIRMAN'S LETTER

The Entergy Corporation Board of Directors' Audit Committee functions as the Audit Committee for Mississippi Power & Light Company. The Audit Committee is comprised of four directors, who are not officers of MP&L: H. Duke Shackelford (Chairman), Lucie J. Fjeldstad, Dr. Norman C. Francis, and James R. Nichols. The committee held four meetings during 1994.

The Audit Committee oversees MP&L's financial reporting process on behalf of the Board of Directors and provides reasonable assurance to the Board that sufficient operating, accounting, and financial controls are in existence and are adequately reviewed by programs of internal and external audits.

The Audit Committee discussed with Entergy's internal auditors and the independent public accountants (Coopers & Lybrand L.L.P.) the overall scope and specific plans for their respective audits, as well as MP&L's financial statements and the adequacy of MP&L's internal controls. The committee met, together and separately, with Entergy's internal auditors and independent public accountants, without management present, to discuss the results of their audits, their evaluation of MP&L's internal controls, and the overall quality of MP&L's financial reporting. The meetings also were designed to facilitate and encourage any private communication between the committee and the internal auditors or independent public accountants.

H. DUKE SHACKELFORD
Chairman, Audit Committee

REPORT OF INDEPENDENT ACCOUNTANTS

To the Board of Directors and Shareholders of
Mississippi Power & Light Company

We have audited the accompanying balance sheet of Mississippi Power & Light Company as of December 31, 1994, and the related statements of income, retained earnings and cash flows for the year then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audit. The financial statements of the Company as of December 31, 1993 and for the years ended December 31, 1993 and 1992, were audited by other auditors, whose report, dated February 11, 1994, included an explanatory paragraph that described changes in methods of accounting for revenues, income taxes and postretirement benefits other than pensions which are discussed in Notes 1, 3 and 9 respectively, to these financial statements.

We conducted our audit in accordance with generally accepted auditing standards. Those standards require that we plan and perform the audit to obtain reasonable assurance 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 audit provides a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 1994, and the result of its operations and its cash flows for the year then ended in conformity with generally accepted accounting principles.

COOPERS & LYBRAND L.L.P.
New Orleans, Louisiana
February 21, 1995

INDEPENDENT AUDITORS' REPORT

To the Shareholders and the Board of Directors of
Mississippi Power & Light Company

We have audited the accompanying balance sheet of Mississippi Power & Light Company (MP&L) as of December 31, 1993, and the related statements of income, retained earnings, and cash flows for each of the two years in the period ended December 31, 1993. These financial statements are the responsibility of MP&L's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with generally accepted auditing standards. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such financial statements present fairly, in all material respects, the financial position of MP&L at December 31, 1993, and the results of its operations and its cash flows for each of the two years in the period ended December 31, 1993 in conformity with generally accepted accounting principles.

As discussed in Note 1 to the financial statements, MP&L changed its method of accounting for revenues in 1993 and, as discussed in Notes 3 and 9 to the financial statements, in 1993 MP&L changed its methods of accounting for income taxes and postretirement benefits other than pensions, respectively.

DELOITTE & TOUCHE LLP
New Orleans, Louisiana
February 11, 1994

MISSISSIPPI POWER & LIGHT COMPANY
BALANCE SHEETS
ASSETS

	December 31,	
	1994	1993
	(In Thousands)	
Utility Plant:		
Electric	$1,475,322	$1,389,229
Construction work in progress	67,119	62,699
Total	1,542,441	1,451,928
Less - accumulated depreciation and amortization	582,514	577,728
Utility plant - net	959,927	874,200
Other Property and Investments:		
Investment in subsidiary company - at equity	5,531	5,531
Other	5,624	4,760
Total	11,155	10,291
Current Assets:		
Cash and cash equivalents:		
Cash	5,080	7,999
Temporary cash investments - at cost, which approximates market		
Associated companies	276	-
Other	4,242	-
Total cash and cash equivalents	9,598	7,999
Notes receivable	9,681	7,118
Accounts receivable:		
Customer (less allowance for doubtful accounts of $2.1 million in 1994 and $2.5 million in 1993)	21,087	33,155
Associated companies	4,680	7,342
Other	2,789	3,672
Accrued unbilled revenues	39,873	57,414
Fuel inventory - at average cost	4,780	8,652
Materials and supplies - at average cost	20,642	20,886
Rate deferrals	106,538	96,935
Prepayments and other	10,672	13,763
Total	230,340	256,936
Deferred Debits and Other Assets:		
Regulatory Assets:		
Rate deferrals	385,720	504,428
Unamortized loss on reacquired debt	10,488	11,656
Other regulatory assets	10,168	2,949
Long-term receivables	13,078	9,951
Other	8,569	6,326
Total	428,023	535,310
TOTAL	$1,629,445	$1,676,737

See Notes to Financial Statements

INDEPENDENT AUDITORS' REPORT

To the Shareholders and the Board of Directors of
Mississippi Power & Light Company

We have audited the accompanying balance sheet of Mississippi Power & Light Company (MP&L) as of December 31, 1993, and the related statements of income, retained earnings, and cash flows for each of the two years in the period ended December 31, 1993. These financial statements are the responsibility of MP&L's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with generally accepted auditing standards. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such financial statements present fairly, in all material respects, the financial position of MP&L at December 31, 1993, and the results of its operations and its cash flows for each of the two years in the period ended December 31, 1993 in conformity with generally accepted accounting principles.

As discussed in Note 1 to the financial statements, MP&L changed its method of accounting for revenues in 1993 and, as discussed in Notes 3 and 9 to the financial statements, in 1993 MP&L changed its methods of accounting for income taxes and postretirement benefits other than pensions, respectively.

DELOITTE & TOUCHE LLP
New Orleans, Louisiana
February 11, 1994

MISSISSIPPI POWER & LIGHT COMPANY
BALANCE SHEETS
ASSETS

	December 31,	
	1994	1993
	(In Thousands)	
Utility Plant:		
Electric	$1,475,322	$1,389,229
Construction work in progress	67,119	62,699
Total	1,542,441	1,451,928
Less - accumulated depreciation and amortization	582,514	577,728
Utility plant - net	959,927	874,200
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Other	5,624	4,760
Total	11,155	10,291
Current Assets:		
Cash and cash equivalents:		
Cash	5,080	7,999
Temporary cash investments - at cost, which approximates market		
Associated companies	276	-
Other	4,242	-
Total cash and cash equivalents	9,598	7,999
Notes receivable	9,681	7,118
Accounts receivable:		
Customer (less allowance for doubtful accounts of $2.1 million in 1994 and $2.5 million in 1993)	21,087	33,155
Associated companies	4,680	7,342
Other	2,789	3,672
Accrued unbilled revenues	39,873	57,414
Fuel inventory - at average cost	4,780	8,652
Materials and supplies - at average cost	20,642	20,886
Rate deferrals	106,538	96,935
Prepayments and other	10,672	13,763
Total	230,340	256,936
Deferred Debits and Other Assets:		
Regulatory Assets:		
Rate deferrals	385,720	504,428
Unamortized loss on reacquired debt	10,488	11,656
Other regulatory assets	10,168	2,949
Long-term receivables	13,078	9,951
Other	8,569	6,326
Total	428,023	535,310
TOTAL	$1,629,445	$1,676,737

See Notes to Financial Statements.

MISSISSIPPI POWER & LIGHT COMPANY
BALANCE SHEETS
CAPITALIZATION AND LIABILITIES

	December 31,	
	1994	1993
	(In Thousands)	
Capitalization:		
Common stock, no par value, authorized		
15,000,000 shares; issued and outstanding		
8,666,357 shares in 1994 and 1993	$199,326	$199,326
Capital stock expense and other	(1,762)	(1,864)
Retained earnings	232,011	236,337
Total common shareholder's equity	429,575	433,799
Preferred stock:		
Without sinking fund	57,881	57,881
With sinking fund	31,770	46,770
Long-term debt	475,233	516,156
Total	994,459	1,054,606
Other Noncurrent Liabilities:		
Obligations under capital leases	552	686
Other	8,984	6,231
Total	9,536	6,917
Current Liabilities:		
Currently maturing long-term debt	65,965	48,250
Notes payable:		
Associated companies	-	11,568
Other	30,000	-
Accounts payable:		
Associated companies	2,350	29,181
Other	30,205	12,157
Customer deposits	22,793	21,474
Taxes accrued	20,821	24,252
Accumulated deferred income taxes	47,515	41,758
Interest accrued	20,377	23,171
Dividends declared	1,626	1,985
Other	28,692	17,303
Total	270,344	231,099
Deferred Credits:		
Accumulated deferred income taxes	301,288	311,616
Accumulated deferred investment tax credits	29,528	37,193
SFAS 109 regulatory liability - net	13,099	23,626
Other	11,191	11,680
Total	355,106	384,115
Commitments and Contingencies (Notes 2 and 8)		
TOTAL	$1,629,445	$1,676,737

See Notes to Financial Statements

MISSISSIPPI POWER & LIGHT COMPANY
STATEMENTS OF CASH FLOWS

	For the Years Ended December 31,		
	1994	1993	1992
		(in Thousands)	
Operating Activities:			
Net income	$48,779	$101,743	$65,036
Noncash items included in net income:			
Cumulative effect of a change in accounting principle	-	(32,706)	-
Change in rate deferrals	109,105	71,555	17,530
Depreciation and amortization	36,592	32,152	31,493
Deferred income taxes and investment tax credits	(34,409)	(17,881)	18,685
Allowance for equity funds used during construction	(1,660)	(928)	(668)
Changes in working capital:			
Receivables	33,154	(11,814)	(924)
Fuel inventory	3,872	(1,327)	2,061
Accounts payable	(8,783)	5,055	(14,365)
Taxes accrued	(3,431)	(4,200)	2,174
Interest accrued	(2,794)	780	105
Other working capital accounts	13,480	(1,120)	1,918
Other	1,209	8,073	(4,272)
Net cash flow provided by operating activities	195,114	149,382	118,773
Investing Activities:			
Construction expenditures	(121,386)	(66,404)	(53,481)
Allowance for equity funds used during construction	1,660	928	668
Net cash flow used in investing activities	(119,726)	(65,476)	(52,813)
Financing Activities:			
Proceeds from issuance of:			
General and refunding bonds	24,534	250,000	65,000
Other long-term debt	15,652	-	-
Common stock	-	-	25,000
Preferred stock	-	-	19,777
Retirement of:			
First mortgage bonds	(18,000)	(204,501)	(101,416)
General and refunding bonds	(30,000)	(55,000)	-
Other long-term debt	(16,045)	(230)	(210)
Redemption of preferred stock	(15,000)	(16,500)	(9,500)
Dividends paid:			
Common stock	(45,600)	(85,800)	(68,400)
Preferred stock	(7,762)	(9,452)	(9,445)
Changes in short-term borrowings	18,432	11,568	-
Net cash flow used in financing activities	(73,789)	(109,915)	(79,194)
Net increase (decrease) in cash and cash equivalents	1,599	(26,009)	(13,234)
Cash and cash equivalents at beginning of period	7,999	34,008	47,242
Cash and cash equivalents at end of period	$9,598	$7,999	$34,008
SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION:			
Cash paid during the period for:			
Interest - net of amount capitalized	$52,737	$52,459	$62,727
Income taxes	$39,000	$58,831	$14,866

See Notes to Financial Statements.

MISSISSIPPI POWER & LIGHT COMPANY

MANAGEMENT'S FINANCIAL DISCUSSION AND ANALYSIS

LIQUIDITY AND CAPITAL RESOURCES

Liquidity is important to MP&L due to the capital intensive nature of its business, which requires large investments in long-lived assets. While large capital expenditures for the construction of new generating capacity are not currently planned, MP&L does require significant capital resources for the periodic maturity of certain series of debt and preferred stock and ongoing construction expenditures. Net cash flow from operations totaled $195 million, $149 million, and $119 million in 1994, 1993, and 1992, respectively. Net cash flow from operations increased in 1994 due primarily to increased collections under the phase-in plan, as discussed below. In recent years, this cash flow, supplemented by cash on hand and issuances of debt and common and preferred stock, has been sufficient to meet substantially all investing and financing requirements, including capital expenditures, dividends, and debt/preferred stock maturities. MP&L's ability to fund these capital requirements results, in part, from its continued efforts to streamline operations and reduce costs, as well as collections under its Grand Gulf 1 rate phase-in plan, which exceed the current cash requirements for Grand Gulf 1-related costs. (In the income statement, these revenue collections are offset by the amortization of previously deferred costs; therefore, there is no effect on net income.) MP&L's Grand Gulf 1 rate phase-in plan will continue to contribute to MP&L's cash position through 1998. See Note 2 for additional information on MP&L's rate phase-in plan. See Note 8 for additional information on MP&L's capital and refinancing requirements in 1995 - 1997. Also, to the extent current market interest and dividend rates allow, MP&L may continue to refinance high-cost debt and preferred stock prior to maturity.

In March 1994, the MPSC issued a final order adopting a formulary incentive rate plan. The order also adopted previously agreed-upon stipulations of a required return on equity of 11% and certain accounting adjustments that resulted in a 4.3% ($28.1 million) reduction in MP&L's June 30, 1993, test-year base revenues effective March 25, 1994. The plan allows for periodic small adjustments in rates based on an annual comparison of earned to benchmark rates of return and upon certain other performance factors. See Note 2 for additional information.

Earnings coverage tests, bondable property additions, and accumulated deferred Grand Gulf 1-related costs recorded as assets, limit the amount of G&R Bonds and preferred stock that MP&L can issue. Based on the most restrictive applicable tests as of December 31, 1994 and assuming an annual interest or dividend rate of 9.25%, MP&L could have issued $246 million of additional G&R Bonds or $95 million of additional preferred stock. Further, MP&L has the conditional ability to issue G&R Bonds against the retirement of bonds, in some cases without satisfying an earnings coverage test.

See Notes 5 and 6 for information on MP&L's financing activities and Note 4 for information on MP&L's short-term borrowings and lines of credit.

MP&L's liquidity was adversely affected during 1994 due to incurring $77 million of repairs and improvements associated with an ice storm in February. See Note 2 for information regarding a rate increase in September to recover ice storm costs.

MISSISSIPPI POWER & LIGHT COMPANY
STATEMENTS OF INCOME

	For the Years Ended December 31,		
	1994	1993	1992
		(In Thousands)	
Operating Revenues	$847,888	$895,806	$817,650
Operating Expenses:			
Operation and maintenance:			
Fuel and fuel-related expenses	160,227	140,391	112,032
Purchased power	235,019	289,016	301,912
Other operation and maintenance	156,954	156,405	146,440
Depreciation and amortization	36,592	32,152	31,493
Taxes other than income taxes	43,963	41,878	40,738
Income taxes	16,651	33,074	21,681
Rate deferrals:			
Rate deferrals	-	-	(22,876)
Amortization of rate deferrals	102,725	77,570	61,456
Total	752,131	770,486	692,876
Operating Income	95,757	125,320	124,774
Other Income (Deductions):			
Allowance for equity funds used during construction	1,660	928	668
Miscellaneous - net	(1,117)	948	4,562
Income taxes - (debit)	4,176	(3,462)	(1,467)
Total	4,719	(1,586)	3,763
Interest Charges:			
Interest on long-term debt	47,835	53,558	62,394
Other interest - net	4,929	1,802	1,672
Allowance for borrowed funds used during construction	(1,067)	(663)	(565)
Total	51,697	54,697	63,501
Income before Cumulative Effect of a Change in Accounting Principle	48,779	69,037	65,036
Cumulative Effect to January 1, 1993 of Accruing Unbilled Revenues (net of income taxes of $19,456)	-	32,706	-
Net Income	48,779	101,743	65,036
Preferred Stock Dividend Requirements and Other	7,624	9,160	9,513
Earnings Applicable to Common Stock	$41,155	$92,583	$55,523

See Notes to Financial Statements.

MISSISSIPPI POWER & LIGHT COMPANY
STATEMENTS OF RETAINED EARNINGS

	For the Years Ended December 31,		
	1994	1993	1992
		(In Thousands)	
Retained Earnings, January 1	$236,337	$230,201	$243,819
Add:			
Net income	48,779	101,743	65,036
Total	285,116	331,944	308,855
Deduct:			
Dividends declared:			
Preferred stock	7,404	8,964	9,513
Common stock	45,600	85,800	68,400
Preferred stock expenses	101	843	741
Total	53,105	95,607	78,654
Retained Earnings, December 31 (Note 7)	$232,011	$236,337	$230,201

See Notes to Financial Statements.

MISSISSIPPI POWER & LIGHT COMPANY

MANAGEMENT'S FINANCIAL DISCUSSION AND ANALYSIS

RESULTS OF OPERATIONS

Net Income

Net income decreased in 1994 due primarily to the one-time recording in the first quarter of 1993 of the cumulative effect of the change in accounting principle for unbilled revenues. In addition, net income was reduced by the rate reduction in connection with the formula incentive rate plan, partially offset by a FERC settlement (see Litigation and Regulatory Proceedings below). Net income increased in 1993 due primarily to the one-time recording of the cumulative effect of the change in accounting principle for unbilled revenues and its ongoing effects, partially offset by the effects of implementing SFAS 109 and SFAS 106. Effective January 1, 1993, MP&L began accruing as revenues the charges for energy delivered to customers but not yet billed. Electric revenues were previously recorded on a cycle-billing basis. Excluding the above mentioned items, net income for 1993 would have been $71.9 million. This $6.9 million increase is due primarily to an increase in retail energy sales and a decrease in interest expense from the refinancing of high-cost debt.

Significant factors affecting the results of operations and causing variances between the years 1994 and 1993, and 1993 and 1992, are discussed under "Revenues and Sales," "Expenses," and "Other" below.

Revenues and Sales

See "Selected Financial Data - Five-Year Comparison" following the notes, for information on operating revenues by source and KWH sales.

Operating revenues decreased in 1994 due to the impact of the rate reduction in connection with the incentive rate plan that went into effect in March 1994, partially offset by higher energy sales. In addition to the factors cited above for revenues, accrued unbilled revenues decreased due to a change in the cycle billing dates offset by an increase in billed revenues. This decrease was partially offset by increased retail energy sales resulting from increased commercial and industrial sales.

Operating revenues were higher in 1993 due to increased residential and commercial energy sales resulting primarily from a return to more normal weather as compared to milder weather in 1992. Industrial energy sales also increased due to higher sales to the rubber and plastics, petroleum refining, and petroleum pipelines sectors. Sales for resale to associated companies were higher due to changes in generation availability and requirements among AP&L, LP&L, MP&L and NOPSI. Additionally, electric operating revenues increased due to increased fuel adjustment revenues and increased collections of previously deferred Grand Gulf 1-related costs, neither of which affects net income. These increases were partially offset by a decrease in other revenue related to MP&L's rate deferral over/under recovery which reflects adjustments for the difference between actual and estimated costs, and does not affect net income.

Expenses

Operating expenses decreased in 1994 due primarily to lower purchased power and income tax expense partially offset by increased amortization of rate deferrals. Operating expenses increased in 1993 due primarily to higher fuel and maintenance expenses and increased amortization of rate deferrals.

Purchased power expense decreased in 1994 due primarily to changes in generation availability and requirements among the System operating companies. A lower per unit price for power purchased also contributed to the decrease in purchased power in 1994.

Fuel for electric generation and fuel-related expenses increased in 1993 due primarily to an increase in generation requirements resulting primarily from increased energy sales, as discussed in "Revenues and Sales" above, and increased fuel costs.

Other operation and maintenance expense was higher in 1993 due primarily to an increase in scheduled maintenance at MP&L's power plants.

Income taxes decreased in 1994 due primary to lower pretax income, and the write-off of unamortized deferred investment tax credits in accordance with a FERC settlement. Income taxes increased in 1993 due to the effect of high pretax income, an increase in the federal income tax rate as a result of OBRA, and the effect of implementing SFAS 109.

The amortization of rate deferrals increased in 1994 and 1993 reflecting the fact that MP&L, based on the Revised Plan, collected more Grand Gulf 1-related costs from its customers in 1994 than it recovered in 1993 and 1992.

Interest expense decreased in 1994 and 1993 due primarily to the refinancing of high-cost long-term debt and the maturity of high-cost long-term debt.

Competition

The electric utility industry is becoming increasingly competitive and MP&L is seeking to become a leading competitor in the changing electric energy business. Competition presents MP&L with many challenges. The following have been identified by MP&L as its major competitive challenges.

Retail and Wholesale Rate Issues

The retail regulatory philosophy is shifting in some jurisdictions from traditional cost of service regulation to incentive rate regulation. Incentive and performance-based rate plans encourage efficiencies and productivity while permitting utilities and their customers to share in the results. MP&L implemented an incentive rate plan in 1994. Recognizing that many industrial customers have energy alternatives, MP&L continues to work with these customers to address their needs. In certain cases, competitive prices are negotiated, using variable rate designs.

MP&L's formulary incentive rate plan allows for periodic small adjustments in rates based on a comparison of earned to benchmark returns and upon certain performance factors. In addition, certain previously agreed-upon stipulations of a required return on equity of 11% and certain accounting adjustments resulted in a 4.3% ($28.1 million) reduction in MP&L's revenues effective March 25, 1994. For further information see Note 2.

In connection with the Merger, MP&L agreed with their respective retail regulators not to request any general retail rate increases that would take effect before November 1998, with certain exceptions.

Retail wheeling, the transmission by an electric utility of energy produced by another entity over the utility's transmission and distribution system to a retail customer in the electric utility's service territory, is evolving. Over a dozen states have been studying the concept of retail competition. In April 1994, the state of Michigan agreed to a five-year experiment that allows limited competition among public utilities. During the same month, the California Public Utilities Commission proposed to deregulate that state's electric power industry, starting on January 1, 1996, to allow the largest industrial customers to select the lowest cost supplier for electricity service. Under the proposal, by the year 2002, smaller companies and residential customers in California would also be able to buy power from any suppliers. The California Public Utilities Commission is currently reviewing its decision and is expected to make a ruling in the first half of 1995. The retail market for electricity is expected to become more competitive with such moves toward deregulation.

In some areas of the country, municipalities (or comparable entities) whose residents are served at retail by an investor-owned utility pursuant to a franchise are exploring the possibility of establishing new or extending existing distribution systems or seeking new delivery points in order to serve retail customers, especially large industrial customers, that currently receive service from an investor-owned utility. These options depend on the terms of a utility's franchise as well as on state law and regulation. In addition, FERC's authority to order utilities to transmit for a new or expanding municipal system is limited in certain respects. Where successful, however, the establishment of a municipal system or the acquisition by a municipal system of a utility's customers could result in the inability to recover costs that the utility has incurred in serving those customers.

On October 11, 1994, twelve Mississippi cities filed a complaint in state court against MP&L and eight electric power associations seeking a judgment from the court declaring unconstitutional certain Mississippi statutes that establish the procedure that must be followed before a municipality can acquire the facilities and certificate rights of a utility serving in the municipality. Specifically, the suit requests that the court declare unconstitutional certain 1987 amendments to the Mississippi Public Utilities Act that require that the MPSC cancel a utility's certificate to serve in the municipality before a municipality may acquire a utility's facilities located in the municipality. The suit also requests that the court find that Mississippi municipalities can serve any consumer in the boundaries of the municipality and within one mile thereof. Such a finding would be contrary to Mississippi Supreme Court decisions that have held that a municipality cannot serve in another utility's service area even where the municipal boundaries extend into such service area. On January 6, 1995, MP&L and the other defendants filed motions to dismiss. The matter is pending and will be vigorously contested by MP&L.

In mid-1994, the FERC issued a notice of proposed rulemaking concerning a regulatory framework for dealing with recovery of stranded costs, such as high cost nuclear generating units, which may be incurred by electric utilities as a result of increased competition. In addition to addressing recovery of stranded costs related to wholesale service, the proposal requested comment as to recovery of retail stranded costs in transmission rates where state regulatory authorities failed to address the issue or were in conflict. Comments and reply comments have been filed, and the matter is pending. The risk of exposure to stranded costs which may result from competition in the industry will depend on the extent and timing of retail competition, the resolution of jurisdictional issues concerning stranded cost recovery and the extent to which such costs are recovered from departing or remaining customers, among other matters.

In the wholesale rate area, FERC approved in 1992, with certain modifications, the proposal of AP&L, LP&L, MP&L, NOPSI, and Entergy Power, Inc. to sell wholesale power at market-based rates and to provide to electric utilities "open access" to the System's transmission system (subject to certain requirements). GSU was later added to this filing. On January 25, 1995, Entergy Services filed with FERC revised transmission tariffs intended to provide access to transmission service on the same or comparable basis, terms, and conditions as the System operating companies. Open access and market pricing, once in effect, will increase marketing opportunities for MP&L, but will also expose MP&L to the risk of loss of load or reduced revenues due to competition with alternative suppliers.

In light of the rate issues discussed above, MP&L is aggressively reducing costs to avoid potential earnings erosions that might result as well as to become more competitive. In 1994, MP&L announced a restructuring program related to certain of its operating units. This program is designed to reduce costs and improve operating efficiencies. See Note 12 for further information. Also, in response to an increasingly competitive environment, MP&L announced intentions to revise its initial least cost planning activities.

The Energy Policy Act of 1992

The EPAct addresses a wide range of energy issues and is altering the way Entergy and the rest of the electric utility industry operate. The EPAct encourages competition and affords utilities the opportunities, and the risks, associated with an open and more competitive market environment. The EPAct creates exemptions from regulation under the Holding Company Act and creates a class of exempt wholesale generators consisting of utility affiliates and nonutilities that are owners and operators of facilities for the generation and transmission of power for sales at wholesale. The EPAct also gives FERC the authority to order investor-owned utilities, including MP&L, to transmit power and energy to or for wholesale purchasers and sellers. The law creates the potential for electric utilities and other power producers to gain increased access to the transmission systems of other entities to facilitate wholesale sales. Both MP&L and Entergy Power expect to compete in this market. In addition, the EPAct allows utilities to own and operate foreign generation, transmission, and distribution facilities.

Litigation and Regulatory Proceedings

In November 1994, FERC approved an agreement settling a long-standing dispute involving income tax allocation procedures of System Energy. In accordance with the agreement, System Energy refunded approximately $20.4 million to MP&L, which will in turn make refunds or credits to its customers. Additionally, System Energy will refund a total of approximately $20.5 million, plus interest, to MP&L over the period through June 2004. The settlement also required the write-off of approximately $6 million of certain unamortized deferred investment tax credits by MP&L.

Accounting Issues

Proposed Accounting Standards - The FASB has proposed a SFAS on "Accounting for the Impairment of Long-Lived Assets," effective January 1, 1996. The proposed standard describes circumstances which may result in assets being impaired and provides criteria for recognition and measurement of asset impairment. Certain operations of MP&L are potentially affected by this standard, and any resulting write-offs will depend on future operating costs, generating units' efficiency and availability, and the future market for energy over the remaining life of the units. Based on current estimates, MP&L anticipates that future revenues will fully recover the costs of such operations.

Continued Application of SFAS 71 - MP&L's financial statements currently reflect assets and costs based on current cost-based ratemaking regulations, in accordance with SFAS 71, "Accounting for the Effects of Certain Types of Regulation." As discussed above, the electric utility industry is changing and these changes could possibly result in the discontinuance of the application of SFAS 71, which would result in the elimination of regulatory assets and liabilities. See Note 1 for further information.

NOTE 1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

MP&L maintains accounts in accordance with FERC and other regulatory guidelines. Certain previously reported amounts have been reclassified to conform to current classifications.

Revenues and Fuel Costs

Prior to January 1, 1993, MP&L recorded revenues when billed to its customers with no accrual for energy delivered but not yet billed. To provide a better matching of revenues and expenses, effective January 1, 1993, MP&L adopted a change in accounting principle to provide for accrual of estimated unbilled revenues. The cumulative effect of this accounting change as of January 1, 1993 increased net income by $32.7 million. Had this new accounting method been in effect during prior years, net income before the cumulative effect would not have been materially different from that shown in the accompanying financial statements.

MP&L's rate schedules include fuel adjustment clauses that allow current recovery of estimated fuel costs, with subsequent adjustments of estimates to actual.

Utility Plant

Utility plant is stated at original cost. The original cost of utility plant retired or removed, plus the applicable removal costs, less salvage, is charged to accumulated depreciation. Maintenance, repairs, and minor replacement costs are charged to operating expenses. Substantially all of MP&L's utility plant is subject to the lien of its first mortgage bond indenture and the second lien of its G&R mortgage bond indenture.

Total MP&L net utility plant in service of $893 million as of December 31, 1994 includes $220 million of production plant, $249 million of transmission plant, $358 million of distribution plant, and $66 million of other plant.

Depreciation is computed on the straight-line basis at rates based on the estimated service lives and costs of removal of the various classes of property. Depreciation provisions on average depreciable property approximated 2.4% in 1994 and 1993, and 2.5% in 1992.

AFUDC represents the approximate net composite interest cost of borrowed funds and a reasonable return on the equity funds used for construction. Although AFUDC increases utility plant and increases earnings, it is only realized in cash through depreciation provisions included in rates. MP&L's effective composite rates for AFUDC were 8.0%, 11.8%, and 12.0%, for 1994, 1993, and 1992, respectively.

Jointly-Owned Generating Station

MP&L owns 25% of the Independence Station, a two-unit, coal-fired generating station located near Newark, Arkansas. The total capability of Independence Station is 1,678 megawatts. MP&L records its investment in and expenses associated with this station to the extent of its ownership and interest. MP&L's investment in the Independence Station was approximately $222 million less accumulated depreciation of approximately $73.6 million as of December 31, 1994.

Notes Receivable

MP&L currently has a program, wherein it finances heat pumps for its customers through notes receivable. Such notes are repayable in equal monthly installments of principal and interest over a five-year period and bear interest at a market-based rate at the time of sale. The amounts financed are classified on its balance sheet as current and noncurrent notes receivable.

Income Taxes

MP&L, its parent, and affiliates file a consolidated federal income tax return. Income taxes are allocated to MP&L in proportion to its contribution to consolidated taxable income. SEC regulations require that no Entergy Corporation subsidiary pay more taxes than it would have had a separate income tax return been filed. Deferred taxes are recorded for all temporary differences between book and taxable income. Investment tax credits are deferred and amortized based upon the average useful life of the related property, in accordance with rate treatment. As discussed in Note 3, in 1993 MP&L changed its accounting for income taxes to conform with SFAS 109.

In addition, MP&L files a consolidated Mississippi state income tax return with certain other System companies.

Cash and Cash Equivalents

MP&L considers all unrestricted highly liquid debt instruments purchased with an original maturity of three months or less to be cash equivalents.

Continued Application of SFAS 71

As a result of the EPAct and actions of regulatory commissions, the electric utility industry is moving toward a combination of competition and a modified regulatory environment. MP&L's financial statements currently reflect assets and costs based on current cost-based ratemaking regulations, in accordance with SFAS 71, "Accounting for the Effects of Certain Types of Regulation." Continued applicability of SFAS 71 to MP&L's financial statements requires that rates set by an independent regulator on a cost of service basis (including a reasonable rate of return on invested capital) can actually be charged to and collected from customers.

In the event that either all or a portion of a utility's operations cease to meet those criteria for various reasons, including deregulation, a change in the method of regulation, or a change in the competitive environment for the utility's regulated services, the utility should discontinue application of SFAS 71 for the relevant portion. That discontinuation should be reported by elimination from the balance sheet of the effects of any actions of regulators recorded as regulatory assets and liabilities.

As of December 31, 1994, and for the foreseeable future, MP&L's financial statements continue to follow SFAS 71.

Fair Value Disclosure

The estimated fair value of financial instruments has been determined by MP&L, using available market information and appropriate valuation methodologies. However, considerable judgment is required in developing the estimates of fair value. Therefore, estimates are not necessarily indicative of the amounts that MP&L could realize in a current market exchange. In addition, gains or losses realized on financial instruments may be reflected in future rates and not accrue to the benefit of stockholders.

MP&L considers the carrying amounts of financial instruments classified as current assets and liabilities to be a reasonable estimate of their fair value because of the short maturity of these instruments. In addition, MP&L does not presently expect that performance of its obligations will be required in connection with certain off-balance sheet commitments and guarantees considered financial instruments. Due to this factor, and because of the related party nature of these commitments and guarantees, determination of fair value is not considered practicable. See Notes 5 and 6 for additional fair value disclosure.

NOTE 2. RATE AND REGULATORY MATTERS

Formula Rate Plan

Under a formulary incentive rate plan (Formula Rate Plan) effective March 25, 1994, MP&L's earned rate of return is calculated automatically every 12 months and compared to and adjusted against a benchmark rate of return (calculated under a separate formula within the Formula Rate Plan). The Formula Rate Plan allows for periodic small adjustments in rates based on a comparison of earned to benchmark returns and upon certain performance factors. In the same proceeding, the MPSC conducted a general review of MP&L's current rates and on March 1, 1994, issued a final order adopting the Formula Rate Plan and previously agreed-upon stipulations of (1) a required return on equity of 11% and (2) certain accounting adjustments that resulted in a 4.3% ($28.1 million) reduction in MP&L's June 30, 1993, test-year base revenues. The MPSC's order required MP&L to file rates designed to provide for this reduction in operating revenues for the test year on or before March 18, 1994, which became effective March 25, 1994. The final order was appealed to the Mississippi Supreme Court on May 17, 1994, by Mississippi Valley Gas Company (MVG) on the grounds that the MPSC issued the final order without having reviewed the cost of MP&L's promotional practices, some of which MVG alleged to be improper. On October 28, 1994, the Mississippi Supreme Court granted MVG's motion to dismiss the appeal.

Merger - Related Rate Agreement

In November 1993, MP&L and the MPSC entered into a settlement agreement whereby the MPSC agreed to withdraw its request for hearings and its objections in the SEC proceeding related to the Merger. MP&L agreed that MP&L's retail ratepayers would be protected from (1) increases in MP&L's cost of capital resulting from risks associated with the Merger; (2) recovery of any portion of the acquisition premium or transactional costs associated with the Merger; (3) certain direct allocations of costs associated with GSU's River Bend nuclear unit; and (4) any losses of GSU resulting from resolution of litigation in connection with its ownership of River Bend. In a related stipulation, MP&L also agreed (a) that retail base rates under its formula rate plan would not be increased above November 1, 1993 levels, and (b) that MP&L would not request any general retail rate increase that would increase retail rates above the level of MP&L's rates in effect as of November 1, 1993, except for, among other things, increases associated with the recovery of deferred Grand Gulf 1-related costs, recovery under the fuel adjustment clause, adjustments for certain taxes, and force majeure (defined to include, among other things, war, natural catastrophes, and high inflation), in each case for a period of five years beginning November 9, 1993.

Grand Gulf 1

MP&L's Revised Plan provides, among other things, for the recovery by MP&L, in equal annual installments over ten years beginning October 1, 1988, of all Grand Gulf 1-related costs deferred through September 30, 1988 pursuant to the Final Order on Rehearing. Additionally, the Revised Plan provided that MP&L defer, in decreasing amounts, a portion of its Grand Gulf 1-related costs over four years beginning October 1, 1988. These deferrals are being recovered by MP&L over a six-year period beginning in October 1992 and ending in September 1998. The Revised Plan also allows for the current recovery of carrying charges on all deferred amounts.

February 1994 Ice Storm/Rate Rider

In early February 1994, an ice storm left more than 80,000 MP&L customers without electric power across the service area. The storm was the most severe natural disaster ever to affect the System, causing damage to transmission and distribution lines, equipment, poles, and facilities in certain areas, primarily in Mississippi. Repair costs totaled approximately $77.2 million, with $64.6 million of these amounts capitalized as plant-related costs. The remaining balances have been recorded as a deferred debit. On April 15, 1994, MP&L filed for rate recovery of costs related to the ice storm. MP&L's filing, as subsequently amended, requested recovery of the revenue requirement associated with MP&L's ice storm costs recorded through April 30, 1994, representing approximately 86% of the total estimated ice storm costs. MP&L may make another ice storm rate filing with the MPSC during 1995 to recover ice storm costs recorded by MP&L after April 30, 1994. In August 1994, MP&L and the MPSC's Public Utilities Staff entered into a stipulation with respect to the recovery of ice storm costs recorded through April 30, 1994, and in September 1994, the MPSC approved the stipulation. Under the stipulation, MP&L implemented an ice storm rider schedule, which went into effect on September 29, 1994, that will increase rates approximately $8 million annually for five years. At the end of the five-year period, the revenue requirement associated with the undepreciated ice storm capitalized costs will be included in MP&L's base rates to the extent that this revenue requirement does not result in MP&L's rate of return on rate base being above the benchmark rate of return under MP&L's formula rate plan.

NOTE 3. INCOME TAXES

Income tax expense consisted of the following:

	For the Years Ended December 31,		
	1994	1993	1992
		(In Thousands)	
Current:			
Federal	$39,505	$46,744	$ 4,532
State	7,379	7,673	(69)
Total	46,884	54,417	4,463
Deferred - net:			
Federal reclassification due to net operating loss	-	-	28,561
State reclassification due to net operating loss	-	-	4,883
Liberalized depreciation	15,880	5,293	9,448
Rate deferral - net	(45,565)	(31,317)	(11,220)
Unbilled revenue	3,167	21,373	(5,722)
Pension liability	434	(647)	(1,233)
Adjustments of prior year taxes	(1,954)	4,299	(3,471)
Bond reacquisition	(447)	3,208	264
Other	1,722	(1,670)	(1,079)
Total	(26,763)	539	20,431
Investment tax credit adjustments - net	(1,673)	1,036	(1,746)
Investment tax credit amortization - FERC settlement	(5,973)	-	-
Recorded income tax expense	$12,475	$55,992	$23,148
Charged to operations	$16,651	$33,074	$21,681
Charged (credited) to other income	(4,176)	3,462	1,467
Charged to cumulative effect	-	19,456	-
Total income taxes	$12,475	$55,992	$23,148

Total income taxes differ from the amounts computed by applying the statutory federal income tax rate to income before taxes. The reasons for the differences were:

	For the Years Ended December 31,					
	1994		1993		1992	
	Amount	% of Pretax Income	Amount	% of Pretax Income	Amount	% of Pretax Income
	(Dollars in Thousands)					
Computed at statutory rate	$21,438	35.0	$55,207	35.0	$29,983	34.0
Increases (reductions) in tax resulting from:						
State income taxes net of federal income tax effect	2,465	4.0	3,253	2.0	2,703	3.1
Depreciation	1,930	3.2	(5,890)	(3.7)	(2,571)	(2.9)
Amortization of excess deferred income taxes	(3,810)	(6.2)	(4,680)	(3.0)	(2,456)	(2.8)
Amortization of investment tax credits	(1,674)	(2.7)	(1,772)	(1.1)	(1,746)	(2.0)
Investment tax credit amortization - FERC settlement	(5,973)	(9.8)	-	-	-	-
Adjustments of prior year taxes	(1,954)	(3.2)	5,228	3.3	(2,760)	(3.2)
SFAS 109 adjustment	-	-	3,439	2.2	-	-
Other - net	53	1	1,207	0.8	(5)	-
Total income taxes	$12,475	20.4	$55,992	35.5	$23,148	26.2

Significant components of MP&L's net deferred tax liabilities as of December 31, 1994 and 1993, were (in thousands):

	1994	1993
Deferred tax liabilities:		
Plant related basis differences	$(173,965)	$(166,650)
Rate deferrals	(201,037)	(246,604)
Other	(13,318)	(6,406)
Total	$(388,320)	$(419,660)
Deferred tax assets:		
Net regulatory liabilities	$ 1,804	$ 9,411
Accumulated deferred investment tax credits	11,295	13,420
Recoverable income tax	-	13,854
Alternative minimum tax credit	-	1,192
Removal cost	2,824	10,725
Standard coal plant	4,717	4,854
Pension related items	3,182	2,488
Other	15,695	10,342
Total	$ 39,517	$ 66,286
Net deferred tax liabilities	$(348,803)	$(353,374)

In accordance with a System Energy FERC settlement, MP&L wrote off $6.0 million of unamortized deferred investment tax credits in 1994.

In 1993, MP&L adopted SFAS 109. SFAS 109 required that deferred income taxes be recorded for all temporary differences and carryforwards, and that deferred tax balances be based on enacted tax laws at tax rates that are expected to be in effect when the temporary differences reverse. SFAS 109 required that regulated enterprises recognize adjustments resulting from implementation as regulatory assets or liabilities if it is probable that such amounts will be recovered from or returned to customers in future rates. A substantial majority of the adjustments required by SFAS 109 was recorded to deferred tax balance sheet accounts with offsetting adjustments to regulatory assets and liabilities. As a result of the adoption of SFAS 109, 1993 net income was reduced by $1.7 million, assets were increased by $50.2 million, and liabilities were increased by $51.9 million. The cumulative effect of the adoption of SFAS 109 is included in income tax expense charged to operations.

NOTE 4. LINES OF CREDIT AND RELATED BORROWINGS

The SEC has authorized MP&L to effect short-term borrowings up to $100 million, which may be increased to as much as $108 million after further SEC approval. This authorization is effective through November 30, 1996. As of December 31, 1994, MP&L had outstanding short-term lines of credit of $30 million from banks within its service territory. Interest rates associated with these lines of credit generally are based on the prime rate, the London interbank offered rate, or a bid rate. Commitment fees on these lines of credit are .125% of the amount of available credit. In addition, MP&L can borrow from the Money Pool, subject to its maximum authorized level of short-term borrowings and the availability of funds. MP&L's short-term borrowings are limited by the terms of its G&R Mortgage to amounts not exceeding the greater of 10% of capitalization or 50% of Grand Gulf 1 rate deferrals available to support the issuance of G&R Bonds. MP&L had no outstanding borrowings under the Money Pool arrangement as of December 31, 1994.

NOTE 5. PREFERRED AND COMMON STOCK

The number of shares and dollar value of MP&L's cumulative, $100 par value preferred stock were:

	As of December 31,				
	Shares Authorized and Outstanding		Total Dollar Value		Call Price Per Share as of December 31,
	1994	1993	1994	1993	1994
			(Dollars in Thousands)		
Without sinking fund:					
4.36% Series	59,920	59,920	$ 5,992	$ 5,992	$103.86
4.56% Series	43,888	43,888	4,389	4,389	$107.00
4.92% Series	100,000	100,000	10,000	10,000	$102.88
7.44% Series	100,000	100,000	10,000	10,000	$102.81
8.36% Series (1)	200,000	200,000	20,000	20,000	-
9.16% Series	75,000	75,000	7,500	7,500	$104.06
Total without sinking fund	578,808	578,808	$57,881	$57,881	
With sinking fund:					
9.00% Series	70,000	140,000	$ 7,000	$14,000	$106.75
9.76% Series	210,000	280,000	21,000	28,000	$102.17
12.00% Series	37,700	47,700	3,770	4,770	$106.00
Total with sinking fund	317,700	467,700	$31,770	$46,770	

(1) This series is not redeemable as of December 31, 1994.

The fair value of MP&L's preferred stock with sinking fund was estimated to be approximately $32.5 million and $49.3 million as of December 31, 1994 and 1993, respectively. The fair values were determined using quoted market prices or estimates from nationally recognized investment banking firms. See Note 1 for additional information on disclosure of fair value of financial instruments.

Changes in the common stock and preferred stock, with and without sinking fund, during the last three years were:

	Number of Shares		
	1994	1993	1992
Common stock issuances($23 issuance price)	-	-	1,086,957
Preferred stock issuances:	-	-	200,000
Preferred stock retirements:	(150,000)	(165,000)	(95,000)

Cash sinking fund requirements for the next five years for preferred stock outstanding as of December 31, 1994, are (in millions): 1995 - $15, 1996 - $7.5, 1997 - $7.5, 1998 - $0.5; and 1999 - $0.5. MP&L has the annual non-cumulative option to redeem at par, additional amounts of its 12.00% Series preferred stock outstanding.

NOTE 6. LONG-TERM DEBT

The long-term debt of MP&L as of December 31, 1994 and 1993, was:

Maturities		Interest Rates			
From	To	From	To	1994	1993
				(In Thousands)	
First Mortgage Bonds					
1995	1996	4-5/8%	6-3/8%	$ 55,000	$ 55,000
G&R Bonds					
1995	1997	5.95%	14.95%*	167,000	215,000
2003	2023	6-5/8%	8.65%	275,000	250,000
Governmental Obligations**					
1995	2004	7-1/2%	8-1/2%	1,880	17,925
2012	2022	7%	11-1/2%	46,030	30,000
Unamortized Premium and Discount-Net				(3,712)	(3,519)
Total Long-Term Debt				541,198	564,406
Less Amount Due Within One Year				65,965	48,250
Long-Term Debt Excluding Amount Due Within One Year				$475,233	$516,156

* The 14.95% series of $20 million was due February 1, 1995. All other series are at interest rates within the range of 5.95% - 11.2%.

** Consists of pollution control revenue bonds, certain series of which are secured by non-interest bearing first mortgage bonds.

The fair value of MP&L's long-term debt as of December 31, 1994 and 1993, was estimated to be $523.1 million and $594.0 million, respectively. The fair values were determined using quoted market prices or estimates from nationally recognized investment banking firms. See Note 1 for additional information on disclosure of fair value of financial instruments.

For the years 1995, 1996, 1997, 1998 and 1999, MP&L has long-term debt maturities and cash sinking fund requirements of (in millions) $66, $61, $96, $0, and $0, respectively. In addition, other sinking fund requirements of approximately $0.4 million for 1995 may be satisfied by cash or by certification of property additions at the rate of 167% of such requirements.

The G&R Mortgage prohibits the issuance of additional first mortgage bonds (including for refunding purposes) under MP&L's first mortgage indenture, except such first mortgage bonds as may hereafter be issued from time to time at MP&L's option to the corporate trustee under the G&R Mortgage to provide additional security for MP&L's G&R Bonds.

Under MP&L's G&R Mortgage Indenture and subject to the earnings coverage test discussed below, G&R Bonds are issuable based upon 70% of property additions since December 31, 1987, plus up to 50% of cumulative deferred Grand Gulf 1-related costs recorded as an asset on the books of MP&L, provided that the maximum amount of G&R Bonds issuable against cumulative deferred Grand Gulf 1-related costs may not exceed $400 million. The G&R Mortgage contains an earnings coverage test requiring a minimum earnings coverage (except for certain refunding issues) of twice the pro-forma annual mortgage interest requirements for the issuance of additional G&R Bonds. As of December 31, 1994, the total amount of G&R Bonds outstanding aggregated $442 million.

NOTE 7. DIVIDEND RESTRICTIONS

MP&L's bond indentures relating to long-term debt contain provisions restricting the payment of cash dividends or other distributions on common stock. As of December 31, 1994, $139.3 million of MP&L's retained earnings were restricted against the payment of cash dividends or other distributions on common stock. On February 1, 1995, MP&L paid Entergy Corporation a $8.3 million cash dividend on common stock.

NOTE 8. COMMITMENTS AND CONTINGENCIES

Capital Requirements and Financing

Construction expenditures for the years 1995, 1996, and 1997 are estimated to total $67.9 each year. MP&L will also require $253 million during the period 1995-1997 to meet long-term debt and preferred stock maturities and cash sinking fund requirements. MP&L plans to meet the above requirements with internally generated funds and cash on hand, supplemented by the issuance of long-term debt. See Notes 5 and 6 regarding the possible issuance, refunding, redemption, purchase or other acquisition of certain outstanding series of preferred stock and long-term debt.

Unit Power Sales Agreement

System Energy has agreed to sell all of its 90% owned and leased share of capacity and energy from Grand Gulf 1 to AP&L, LP&L, MP&L, and NOPSI in accordance with specified percentages (AP&L 36%, LP&L 14%, MP&L 33%, and NOPSI 17%) as ordered by FERC. Charges under this agreement are paid in consideration for MP&L's respective entitlement to receive capacity and energy, and are payable irrespective of the quantity of energy delivered so long as the unit remains in commercial operation. The agreement will remain in effect until terminated by the parties and approved by FERC, most likely upon Grand Gulf 1's retirement from service. MP&L's monthly obligation for payments under the agreement is approximately $16 million.

Availability Agreement

AP&L, LP&L, MP&L, and NOPSI are individually obligated to make payments or subordinated advances to System Energy in accordance with stated percentages (AP&L 17.1%, LP&L 26.9%, MP&L 31.3%, and NOPSI 24.7%) in amounts that when added to amounts received under the Unit Power Sales Agreement or otherwise, are adequate to cover all of System Energy's operating expenses. System Energy has assigned its rights to payments and advances to certain creditors as security for certain obligations. Since commercial operation of Grand Gulf 1, payments under the Unit Power Sales Agreement have exceeded the amounts payable under the Availability Agreement. Accordingly, no payments have ever been required.

Reallocation Agreement

System Energy and AP&L, LP&L, MP&L, and NOPSI entered into the Reallocation Agreement relating to the sale of capacity and energy from the Grand Gulf Station and the related costs, in which LP&L, MP&L, and NOPSI agreed to assume all of AP&L's responsibilities and obligations with respect to the Grand Gulf Station under the Availability Agreement. FERC's decision allocating a portion of Grand Gulf 1 capacity and energy to AP&L supersedes the Reallocation Agreement as it relates to Grand Gulf 1. Responsibility for any Grand Gulf 2 amortization amounts has been individually allocated (LP&L 26.23%, MP&L 43.97%, and NOPSI 29.80%) under the terms of the Reallocation Agreement. However, the Reallocation Agreement does not affect AP&L's obligation to System Energy's lenders under the assignments referred to in the preceding paragraph. AP&L would be liable for its share of such amounts if LP&L, MP&L, and NOPSI were unable to meet their contractual obligations. No payments of any amortization amounts will be required as long as amounts paid to System Energy under the Unit Power Sales Agreement, including other funds available to System Energy, exceed amounts required under the Availability Agreement, which is expected to be the case for the foreseeable future.

System Fuels

MP&L has a 19% interest in System Fuels, a jointly-owned subsidiary of AP&L, LP&L, MP&L, and NOPSI. The parent companies of System Fuels, including MP&L, agreed to make loans to System Fuels to finance its fuel procurement, delivery, and storage activities. As of December 31, 1994, MP&L had approximately $5.5 million of loans outstanding to System Fuels which mature in 2008.

On April 30, 1993, AP&L assumed System Fuels' rights and obligations in connection with System Fuels' coal car leases. The other parent companies of System Fuels have been released from their obligations with respect to the coal car leases. However, MP&L, as a co-owner of the Independence Station, which uses the coal transported by the leased coal cars, will continue to reimburse AP&L for MP&L's share of the costs associated with the leases.

Fuel Purchase Commitments

MP&L owns certain coal mining equipment and facilities at a mine in Wyoming. The mine's estimated reserves are presently expected to provide the projected requirements of the Independence Station through at least 2011.

NOTE 9. POSTRETIREMENT BENEFITS

Pension Plan

MP&L has a defined benefit pension plan covering substantially all of its employees. The pension plan is noncontributory and provides pension benefits based on employees' credited service and average compensation, generally during the last five years before retirement. MP&L funds pension costs in accordance with contribution guidelines established by the Employee Retirement Income Security Act of 1974, as amended, and the Internal Revenue Code of 1986, as amended. The assets of the plan consist primarily of common and preferred stocks, fixed income securities, interest in a money market fund, and insurance contracts.

MP&L's 1994, 1993, and 1992 pension cost, including amounts capitalized, included the following components:

	For the Years Ended December 31,		
	1994	1993	1992
	(In Thousands)		
Service cost - benefits earned during the period	$ 2,484	$ 2,409	$ 2,059
Interest cost on projected benefit obligation	8,648	8,583	8,269
Actual return on plan assets	1,507	(15,053)	(8,474)
Net amortization and deferral	(11,843)	5,325	(1,009)
Net pension cost	$ 796	$ 1,264	$ 845

The funded status of MP&L's pension plan as of December 31, 1994 and 1993, was:

	1994	1993
	(In Thousands)	
Actuarial present value of accumulated pension plan benefits:		
Vested	$ 94,978	$101,664
Nonvested	299	390
Accumulated benefit obligation	$ 95,277	$102,054
Plan assets at fair value	$117,853	$126,990
Projected benefit obligation	109,250	122,056
Plan assets in excess of projected benefit obligation	8,603	4,934
Unrecognized prior service cost	4,198	3,574
Unrecognized transition asset	(8,752)	(10,003)
Unrecognized net gain	(8,138)	(1,798)
Accrued pension liability	$ (4,089)	$ (3,293)

The significant actuarial assumptions used in computing the information above for 1994, 1993, and 1992 were as follows: weighted average discount rate, 8.5% for 1994, 7.5% for 1993 and 8.25% for 1992; weighted average rate of increase in future compensation levels, 5.1% for 1994 and 5.6% for 1993 and 1992; and expected long-term rate of return on plan assets, 8.5%. Transition assets are being amortized over 15 years.

Other Postretirement Benefits

MP&L also provides certain health care and life insurance benefits for retired employees. Substantially all employees may become eligible for these benefits if they reach retirement age while still working for MP&L. The cost of providing these benefits, recorded on a cash basis, to retirees in 1992 was approximately $1.6 million.

Effective January 1, 1993, MP&L adopted SFAS 106. This standard required a change from a cash method to an accrual method of accounting for postretirement benefits other than pensions. At January 1, 1993, the actuarially determined accumulated postretirement benefit obligation (APBO) earned by retirees and active employees was estimated to be approximately $30 million. This obligation is being amortized over a 20-year period beginning in 1993. MP&L is expensing its SFAS 106 costs, which is reflected in rates pursuant to an order from the MPSC in connection with MP&L's formulary incentive rate plan (see Note 2). In conjunction with such rate incentive plan, MP&L has established and commenced funding two Voluntary Employee's Beneficiary Association (VEBA) trusts (for bargaining and non-bargaining unit employees). During 1994, MP&L funded $2.9 million to these VEBA trusts. The trust's assets are invested in a money market fund.

MP&L's 1994 and 1993 postretirement benefit cost, including amounts capitalized and deferred, included the following components:

	1994	1993
	(In Thousands)	
Service cost - benefits earned during the period	$ 876	$ 812
Interest cost on APBO	1,833	2,400
Net amortization and deferral	1,122	1,502
Net periodic postretirement benefit cost	$ 3,831	$ 4,714

The funded status of MP&L's postretirement plan as of December 31, 1994 and 1993, was

	1994	1993
	(In Thousands)	
Accumulated postretirement benefit obligations:		
Retirees	$ 15,531	$ 21,435
Other fully eligible participants	4,293	5,816
Other active participants	3,561	7,794
	23,385	35,045
Plan assets at fair value	2,949	-
Plan assets less than APBO	(20,436)	(35,045)
Unrecognized transition obligation	27,035	28,537
Unrecognized net loss (gain)	(8,636)	3,745
Accrued post retirement benefit liability	$ (2,037)	$ (2,763)

The assumed health care cost trend rate used in measuring the APBO was 9.4% for 1995, gradually decreasing each successive year until it reaches 5.0% in 2011. A one percentage-point increase in the assumed health care cost trend rate for each year would have increased the APBO as of December 31, 1994, by 7.4% and the sum of the service cost and interest cost by approximately 9.5%. The assumed discount rate and rate of increase in future compensation used in determining the APBO were 8.5% for 1994 and 7.5% for 1993 and 5.1% for 1994 and 5.5% for 1993, respectively.

NOTE 10. TRANSACTIONS WITH AFFILIATES

MP&L buys electricity from and/or sells electricity to the other System operating companies and System Energy under rate schedules filed with FERC. In addition, MP&L purchases fuel from System Fuels and receives technical and advisory services from Entergy Services.

Operating revenues include revenues from sales to affiliates amounting to $45.8 million in 1994, $40.6 million in 1993, and $18 million in 1992. Operating expenses include charges from affiliates for fuel costs, purchased power and related charges, and technical and advisory services totaling $280.2 million in 1994, $360.5 million in 1993, and $364 million in 1992.

See Note 1 for information on MP&L's jointly-owned generating station.

NOTE 11. RESTRUCTURING COSTS

During the third quarter of 1994, MP&L announced a restructuring program related to certain of its operating units. The program is designed to reduce costs, improve operating efficiencies, and increase shareholder value in order to enable MP&L to become a low-cost producer. The program includes reductions in the number of employees and the consolidation of offices and facilities. In 1994, MP&L recorded restructuring charges of $6.2 million. These charges primarily include employee severance costs related to the expected termination of approximately 262 employees. As of December 31, 1994, no employees have been terminated and no termination benefits have been paid under this restructuring program.

The significant actuarial assumptions used in computing the information above for 1994, 1993, and 1992 were as follows: weighted average discount rate, 8.5% for 1994, 7.5% for 1993 and 8.25% for 1992; weighted average rate of increase in future compensation levels, 5.1% for 1994 and 5.6% for 1993 and 1992; and expected long-term rate of return on plan assets, 8.5%. Transition assets are being amortized over 15 years.

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MP&L also provides certain health care and life insurance benefits for retired employees. Substantially all employees may become eligible for these benefits if they reach retirement age while still working for MP&L. The cost of providing these benefits, recorded on a cash basis, to retirees in 1992 was approximately $1.6 million.

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	(In Thousands)	
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Other active participants	3,561	7,794
	23,385	35,045
Plan assets at fair value	2,949	-
Plan assets less than APBO	(20,436)	(35,045)
Unrecognized transition obligation	27,035	28,537
Unrecognized net loss (gain)	(8,636)	3,745
Accrued post retirement benefit liability	$ (2,037)	$ (2,763)

The assumed health care cost trend rate used in measuring the APBO was 9.4% for 1995, gradually decreasing each successive year until it reaches 5.0% in 2011. A one percentage-point increase in the assumed health care cost trend rate for each year would have increased the APBO as of December 31, 1994, by 7.4% and the sum of the service cost and interest cost by approximately 9.5%. The assumed discount rate and rate of increase in future compensation used in determining the APBO were 8.5% for 1994 and 7.5% for 1993 and 5.1% for 1994 and 5.5% for 1993, respectively.

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Operating revenues include revenues from sales to affiliates amounting to $45.8 million in 1994, $40.6 million in 1993, and $18 million in 1992. Operating expenses include charges from affiliates for fuel costs, purchased power and related charges, and technical and advisory services totaling $280.2 million in 1994, $360.5 million in 1993, and $364 million in 1992.

See Note 1 for information on MP&L's jointly-owned generating station.

NOTE 11. RESTRUCTURING COSTS

During the third quarter of 1994, MP&L announced a restructuring program related to certain of its operating units. The program is designed to reduce costs, improve operating efficiencies, and increase shareholder value in order to enable MP&L to become a low-cost producer. The program includes reductions in the number of employees and the consolidation of offices and facilities. In 1994, MP&L recorded restructuring charges of $6.2 million. These charges primarily include employee severance costs related to the expected termination of approximately 262 employees. As of December 31, 1994, no employees have been terminated and no termination benefits have been paid under this restructuring program.

NOTE 12. QUARTERLY FINANCIAL DATA (UNAUDITED)

MP&L's business is subject to seasonal fluctuations with the peak period occurring during the third quarter. Operating results for the four quarters of 1994 and 1993 were:

	Operating Revenues	Operating Income	Net Income
		(In Thousands)	
1994:			
First Quarter	$187,417	$18,715	$ 6,249
Second Quarter	$229,790	$33,828	$21,653
Third Quarter	$234,274	$23,675	$10,856
Fourth Quarter	$196,407	$19,539	$10,021
1993:			
First Quarter	$179,467	$24,134	$42,782
Second Quarter	$229,506	$38,471	$25,339
Third Quarter	$264,419	$39,896	$26,921
Fourth Quarter	$222,414	$22,819	$ 6,701

See Note 1 for information regarding the recording of the cumulative effect of the change in accounting principle for unbilled revenues in January 1993.

MISSISSIPPI POWER & LIGHT COMPANY

SELECTED FINANCIAL DATA - FIVE-YEAR COMPARISON

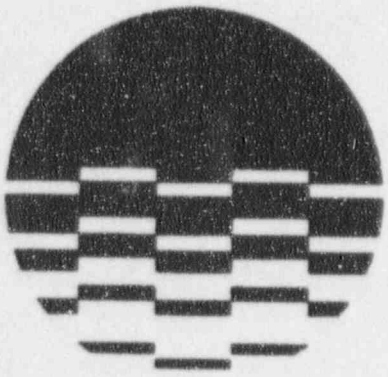
	1994	1993	1992	1991	1990
			(In Thousands)		
Operating revenues	$ 847,888	$ 895,806	$ 817,650	$ 754,632	$ 761,188
Income before cumulative effect of a change in accounting principle	$ 48,779	$ 69,037	$ 65,036	$ 63,088	$ 60,830
Total assets	$1,629,445	$1,676,737	$1,660,726	$1,672,275	$1,616,522
Long-term obligations (1)	$ 507,555	$ 563,612	$ 576,787	$ 576,599	$ 679,458

(1) Includes long-term debt (excluding currently maturing debt), preferred stock with sinking fund, and noncurrent capital lease obligations.

See Notes 1, 3, and 9 for the effect of accounting changes in 1993.

	1994	1993	1992	1991	1990
			(Dollars in Thousands)		
Operating Revenues:					
Residential	$331,007	$343,585	$308,346	$307,283	$302,622
Commercial	255,898	252,798	235,137	229,597	227,140
Industrial	183,398	183,537	168,853	162,072	160,007
Governmental	27,349	28,708	26,250	25,630	25,117
Total retail	797,652	808,628	738,586	724,582	714,886
Sales for resale	54,475	55,740	37,983	25,487	35,678
Other	(4,239)	31,438	41,081	4,563	10,624
Total	$847,888	$895,806	$817,650	$754,632	$761,188
Billed Electric Energy Sales (Millions of KWH):					
Residential	4,014	3,983	3,644	3,739	3,701
Commercial	3,151	2,928	2,804	2,807	2,802
Industrial	2,985	2,787	2,631	2,582	2,564
Governmental	330	336	318	321	318
Total retail	10,480	10,034	9,397	9,449	9,385
Sales for resale	1,591	1,428	1,190	1,032	902
Total	12,071	11,462	10,587	10,481	10,287

New Orleans Public Service Inc./1994 Financial Statements



NOPSI

NEW ORLEANS PUBLIC SERVICE INC.

DEFINITIONS

Certain abbreviations or acronyms used in NOPSI's Financial Statements, Notes to Financial Statements, and Management's Financial Discussion and Analysis are defined below:

Abbreviation or Acronym	Term
AFUDC	Allowance for Funds Used During Construction
Alliance	Alliance for Affordable Energy, and others
AP&L	Arkansas Power & Light Company
City of New Orleans or City	New Orleans, Louisiana
Council	Council of the City of New Orleans, Louisiana
Entergy or System	Entergy Corporation and its various direct and indirect subsidiaries
Entergy Services	Entergy Services, Inc.
EPAct	The Energy Policy Act of 1992
FASB	Financial Accounting Standards Board
February 4 Resolution	The Resolution (including the Determinations and Order referred to therein) adopted by the Council on February 4, 1988, disallowing the recovery by NOPSI of $135 million of previously deferred Grand Gulf 1-related costs
FERC	Federal Energy Regulatory Commission
G&R Bonds	General and Refunding Mortgage Bonds issued and issuable by NOPSI
Grand Gulf 1	Unit No. 1 of the Grand Gulf Station (nuclear)
Grand Gulf 2	Unit No. 2 of the Grand Gulf Station (nuclear)
Grand Gulf Station	Grand Gulf Steam Electric Generating Station (nuclear)
GSU	Gulf States Utilities Company (including wholly owned subsidiaries - Varibus Corporation, GSG&T, Inc., Prudential Oil and Gas, Inc., and Southern Gulf Railway Company)
KWH	Kilowatt-Hour(s)
LP&L	Louisiana Power & Light Company

Abbreviation or Acronym	Term
Merger	The combination transaction, consummated on December 31, 1993, by which GSU became a subsidiary of Entergy Corporation and Entergy Corporation became a Delaware Corporation
Money Pool	Entergy Money Pool, which allows certain System companies to borrow from, or lend to, certain other System companies
MP&L	Mississippi Power & Light Company
1986 Rate Settlement	Agreement, effective March 25, 1986, between NOPSI and the Council regarding NOPSI's Grand Gulf 1-related rate issues
1989 Settlement Agreement	An agreement between the Council and NOPSI, effective July 21, 1989, that settled certain local retail rate issues regarding Grand Gulf 1
1991 NOPSI Settlement	Settlement, retroactive to October 4, 1991, among NOPSI, the Council and the Alliance that settled certain Grand Gulf 1 prudence issues and litigation related to the February 4 Resolution
NOPSI	New Orleans Public Service Inc.
OBRA	Omnibus Budget Reconciliation Act of 1993
SEC	Securities and Exchange Commission
SFAS	Statement of Financial Accounting Standards promulgated by the FASB
SFAS 106	SFAS 106, "Employers' Accounting for Postretirement Benefits Other Than Pensions"
SFAS 109	SFAS 109, "Accounting for Income Taxes"
System Energy	System Energy Resources, Inc.
System Fuels	System Fuels, Inc.
System operating companies	AP&L, GSU, LP&L, MP&L, and NOPSI, collectively
System or Entergy	Entergy Corporation and its various direct and indirect subsidiaries

NEW ORLEANS PUBLIC SERVICE INC.

REPORT OF MANAGEMENT

The management of New Orleans Public Service Inc. has prepared and is responsible for the financial statements and related financial information included herein. The financial statements are based on generally accepted accounting principles. Financial information included elsewhere in this report is consistent with the financial statements.

To meet its responsibilities with respect to financial information, management maintains and enforces a system of internal accounting controls that is designed to provide reasonable assurance, on a cost-effective basis, as to the integrity, objectivity, and reliability of the financial records, and as to the protection of assets. This system includes communication through written policies and procedures, an employee Code of Conduct, and an organizational structure that provides for appropriate division of responsibility and the training of personnel. This system is also tested by a comprehensive internal audit program.

The independent public accountants provide an objective assessment of the degree to which management meets its responsibility for fairness of financial reporting. They regularly evaluate the system of internal accounting controls and perform such tests and other procedures as they deem necessary to reach and express an opinion on the fairness of the financial statements.

Management believes that these policies and procedures provide reasonable assurance that its operations are carried out with a high standard of business conduct.

EDWIN LUPBERGER
Chairman and Chief Executive Officer

GERALD D. MCINVALE
Senior Vice President and
Chief Financial Officer

NEW ORLEANS PUBLIC SERVICE INC.

AUDIT COMMITTEE CHAIRMAN'S LETTER

The Entergy Corporation Board of Directors' Audit Committee functions as the Audit Committee for New Orleans Public Service Inc. The Audit Committee is comprised of four directors, who are not officers of NOPSI: H. Duke Shackelford (Chairman), Lucie J. Fjeldstad, Dr. Norman C. Francis, and James R. Nichols. The committee held four meetings during 1994.

The Audit Committee oversees NOPSI's financial reporting process on behalf of the Board of Directors and provides reasonable assurance to the Board that sufficient operating, accounting, and financial controls are in existence and are adequately reviewed by programs of internal and external audits.

The Audit Committee discussed with Entergy's internal auditors and the independent public accountants (Coopers & Lybrand L.L.P.) the overall scope and specific plans for their respective audits, as well as NOPSI's financial statements and the adequacy of NOPSI's internal controls. The committee met, together and separately, with Entergy's internal auditors and independent public accountants, without management present, to discuss the results of their audits, their evaluation of NOPSI's internal controls, and the overall quality of NOPSI's financial reporting. The meetings also were designed to facilitate and encourage any private communication between the committee and the internal auditors or independent public accountants.

H. DUKE SHACKELFORD
Chairman, Audit Committee

REPORT OF INDEPENDENT ACCOUNTANTS

To the Board of Directors and Shareholders of
New Orleans Public Service Inc.

We have audited the accompanying balance sheet of New Orleans Public Service Inc. as of December 31, 1994, and the related statements of income, retained earnings and cash flows for the year then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audit. The financial statements of the Company as of December 31, 1993 and for the years ended December 31, 1993 and 1992, were audited by other auditors, whose report, dated February 11, 1994, included an explanatory paragraph that described changes in methods of accounting for revenues, income taxes and postretirement benefits other than pensions which are discussed in Notes 1, 3 and 9 respectively, to these financial statements.

We conducted our audit in accordance with generally accepted auditing standards. Those standards require that we plan and perform the audit to obtain reasonable assurance 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 audit provides a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 1994, and the result of its operations and its cash flows for the year then ended in conformity with generally accepted accounting principles.

COOPERS & LYBRAND L.L.P.
New Orleans, Louisiana
February 21, 1995

INDEPENDENT AUDITORS' REPORT

To the Shareholders and the Board of Directors of
New Orleans Public Service Inc.

We have audited the accompanying balance sheet of New Orleans Public Service Inc. (NOPSI) as of December 31, 1993, and the related statements of income, retained earnings, and cash flows for each of the two years in the period ended December 31, 1993. These financial statements are the responsibility of NOPSI's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with generally accepted auditing standards. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such financial statements present fairly, in all material respects, the financial position of NOPSI at December 31, 1993, and the results of its operations and its cash flows for each of the two years in the period ended December 31, 1993 in conformity with generally accepted accounting principles.

As discussed in Note 1 to the financial statements, NOPSI changed its method of accounting for revenues in 1993 and, as discussed in Notes 3 and 9 to the financial statements, in 1993 NOPSI changed its methods of accounting for income taxes and postretirement benefits other than pensions, respectively.

DELOITTE & TOUCHE LLP
New Orleans, Louisiana
February 11, 1994

NEW ORLEANS PUBLIC SERVICE INC.
BALANCE SHEETS
ASSETS

	December 31,	
	1994	1993
	(In Thousands)	
Utility Plant:		
Electric	$470,560	$476,976
Natural gas	119,508	113,666
Construction work in progress	7,284	15,205
Total	597,352	605,847
Less - accumulated depreciation and amortization	319,576	330,268
Utility plant - net	277,776	275,579
Other Investments:		
Investment in subsidiary company - at equity	3,259	3,259
Current Assets:		
Cash and cash equivalents:		
Cash	849	1,176
Temporary cash investments - at cost, which approximates market:		
Associated companies	2,472	10,034
Other	4,710	32,107
Total cash and cash equivalents	8,031	43,317
Accounts receivable:		
Customer (less allowance for doubtful accounts of $0.8 million in 1994 and 1993)	23,938	35,801
Associated companies	3,503	1,378
Other	600	876
Accrued unbilled revenues	14,295	19,643
Deferred electric fuel and resale gas costs	856	6,323
Materials and supplies - at average cost	9,676	9,795
Rate deferrals	31,544	24,587
Income tax receivable	20,172	-
Prepayments and other	5,636	5,084
Total	118,251	146,804
Deferred Debits and Other Assets:		
Regulatory Assets		
Rate deferrals	173,127	204,190
SFAS 109 regulatory asset - net	8,792	9,004
Unamortized loss on reacquired debt	2,361	2,790
Other regulatory assets	5,647	4,027
Other	3,681	1,952
Total	193,608	221,963
TOTAL	$592,894	$647,605

See Notes to Financial Statements.

NEW ORLEANS PUBLIC SERVICE INC.
BALANCE SHEETS
CAPITALIZATION AND LIABILITIES

	December 31,	
	1994	1993
	(In Thousands)	
Capitalization:		
Common stock, $4 par value, authorized 10,000,000 shares; issued and outstanding 8,435,900 shares in 1994 and 1993	$33,744	$33,744
Paid-in capital	36,201	36,156
Retained earnings subsequent to the elimination of the accumulated deficit on November 30, 1988	78,886	100,556
Total common shareholder's equity	148,831	170,456
Preferred stock:		
Without sinking fund	19,780	19,780
With sinking fund	3,450	4,950
Long-term debt	164,160	188,312
Total	336,221	383,498
Other Noncurrent Liabilities:		
Accumulated provision for losses	17,318	18,062
Other	1,745	3,351
Total	19,063	21,413
Current Liabilities:		
Currently maturing long-term debt	24,200	15,000
Accounts payable:		
Associated companies	6,456	23,080
Other	19,503	22,011
Customer deposits	17,422	16,617
Accumulated deferred income taxes	4,925	4,968
Taxes accrued	2,329	5,161
Interest accrued	5,242	5,472
Other	19,982	7,367
Total	100,059	99,676
Deferred Credits:		
Accumulated deferred income taxes	89,246	105,096
Accumulated deferred investment tax credits	9,251	11,592
Other	39,054	26,330
Total	137,551	143,018
Commitments and Contingencies (Notes 2 and 8)		
TOTAL	$592,894	$647,605

See Notes to Financial Statements.

NEW ORLEANS PUBLIC SERVICE INC.
STATEMENTS OF CASH FLOWS

	For the Years Ended December 31,		
	1994	1993	1992
		(In Thousands)	
Operating Activities:			
Net income	$13,211	$47,709	$26,424
Noncash items included in net income:			
Cumulative effect of a change in accounting principle	-	(10,948)	-
Change in rate deferrals	24,106	15,842	2,856
Depreciation and amortization	19,275	17,284	16,619
Deferred income taxes and investment tax credits	(18,006)	(2,132)	(865)
Allowance for equity funds used during construction	(331)	(141)	(119)
Net pension expense	-	-	(23,131)
Changes in working capital:			
Receivables	15,362	(6,725)	1,579
Accounts payable	(19,132)	1,169	(1,455)
Taxes accrued	(2,832)	(82)	1,473
Interest accrued	(230)	(1,319)	(1,687)
Income tax receivable	(20,172)	-	-
Other working capital accounts	18,454	1,365	(6,344)
Other	8,851	8,345	7,047
Net cash flow provided by operating activities	38,556	70,367	22,397
Investing Activities:			
Construction expenditures	(22,777)	(24,813)	(21,043)
Allowance for equity funds used during construction	331	141	119
Net cash flow used in investing activities	(22,446)	(24,672)	(20,924)
Financing Activities:			
Proceeds from the issuance of general and refunding bonds	-	100,000	-
Retirement of:			
First mortgage bonds	-	(56,823)	(28,000)
General and refunding bonds	(15,000)	(44,400)	-
Redemption of preferred stock	(1,500)	(1,500)	(1,500)
Dividends paid:			
Common stock	(33,300)	(43,900)	(32,154)
Preferred stock	(1,596)	(1,825)	(2,057)
Net cash flow used in financing activities	(51,396)	(48,448)	(63,711)
Net decrease in cash and cash equivalents	(35,286)	(2,753)	(62,238)
Cash and cash equivalents at beginning of period	43,317	46,070	108,308
Cash and cash equivalents at end of period	$8,031	$43,317	$46,070
SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION:			
Cash paid during the period for:			
Interest - net of amount capitalized	$17,707	$21,953	$26,330
Income taxes	$45,984	$25,661	$15,632

See Notes to Financial Statements.

LIQUIDITY AND CAPITAL RESOURCES

Liquidity is important to NOPSI due to the capital intensive nature of its business, which requires large investments in long-lived assets. While large capital expenditures for the construction of new generating capacity are not currently planned, NOPSI does require significant capital resources for the periodic maturity of certain series of debt and preferred stock and ongoing construction expenditures. Net cash flow from operations totaled $39 million, $70 million, and $22 million in 1994, 1993, and 1992, respectively. Net cash flow from operations decreased in 1994 due primarily to the effects of the 1994 NOPSI Settlement, as discussed below. In recent years, this cash flow, supplemented by cash on hand, has been sufficient to meet substantially all investing and financing requirements, including capital expenditures, dividends, and debt/preferred stock maturities. NOPSI's ability to fund these capital requirements results, in part, from its continued efforts to streamline operations and reduce costs, as well as collections under its Grand Gulf 1 rate phase-in plan which exceed the current cash requirements for Grand Gulf 1-related costs. (In the income statement, these revenue collections are offset by the amortization of previously deferred costs; therefore, there is no effect on net income.) NOPSI's Grand Gulf 1 rate phase-in plan will continue to contribute to NOPSI's cash position through 2001. See Note 2 for additional information on NOPSI's rate phase-in plan. See Note 8 for additional information on NOPSI's capital and refinancing requirements in 1995 - 1997. Also, to the extent current market interest and dividend rates allow, NOPSI may continue to refinance high-cost debt and preferred stock prior to maturity.

As discussed in Note 2, NOPSI agreed to reduce electric and gas rates and issue credits and refunds to customers pursuant to the 1994 NOPSI Settlement. Under the terms of the settlement, NOPSI implemented rate reductions totaling $44.9 million effective January 1, 1995. NOPSI will implement an additional $4.4 million rate reduction on October 31, 1995. In addition, the 1994 NOPSI Settlement requires NOPSI to credit its customers $25 million over a 21-month period beginning January 1, 1995, in order to resolve disputes with the Council regarding the interpretation of the 1991 NOPSI Settlement. The 1994 NOPSI Settlement also required NOPSI to refund $9.3 million of overcollections associated with Grand Gulf 1 operating costs and $10.5 million of refunds associated with the settlement by System Energy of a FERC tax audit. See Note 2 for additional information.

Earnings coverage tests, bondable property additions, and accumulated deferred Grand Gulf 1-related costs recorded as assets, limit the amount of G&R Bonds and preferred stock that NOPSI can issue. Based on the most restrictive applicable tests as of December 31, 1994, and an assumed annual interest or dividend rate of 9.25%, NOPSI could have issued $73 million of additional G&R Bonds or $17 million of additional preferred stock. Further, NOPSI has the conditional ability to issue G&R Bonds against the retirement of bonds, in some cases without satisfying an earnings coverage test.

See Notes 5 and 6 for information on NOPSI's financing activities and Note 4 for information on NOPSI's short-term borrowings and lines of credit.

NEW ORLEANS PUBLIC SERVICE INC.
STATEMENTS OF INCOME

	For the Years Ended December 31,		
	1994	1993	1992
	(In Thousands)		
Operating Revenues:			
Electric	$360,430	$423,830	$391,936
Natural gas	87,357	90,992	72,943
Total	447,787	514,822	464,879
Operating Expenses:			
Operation and maintenance:			
Fuel, fuel-related expenses and gas purchased for resale	113,735	112,451	90,778
Purchased power	145,935	165,963	170,703
Other operation and maintenance	80,656	87,797	91,735
Depreciation and amortization	19,275	17,284	16,619
Taxes other than income taxes	27,814	26,643	27,487
Income taxes	3,602	24,232	14,382
Rate deferrals:			
Rate deferrals	-	(1,651)	(1,300)
Amortization of rate deferrals	27,009	22,351	4,426
Total	418,026	455,070	414,830
Operating Income	29,761	59,752	50,049
Other Income (Deductions):			
Allowance for equity funds used during construction	331	141	119
Miscellaneous - net	2,141	(1,055)	3,056
Income taxes	(998)	(1,115)	(1,683)
Total	1,474	(2,029)	1,492
Interest Charges:			
Interest on long-term debt	17,092	20,076	23,510
Other interest - net	1,179	1,016	1,714
Allowance for borrowed funds used during construction	(247)	(130)	(107)
Total	18,024	20,962	25,117
Income before Cumulative Effect of a Change in Accounting Principle	13,211	36,761	26,424
Cumulative Effect to January 1, 1993 of Accruing Unbilled Revenues (net of income taxes of $6,592)	-	10,948	-
Net Income	13,211	47,709	26,424
Preferred Stock Dividend Requirements and Other	1,581	1,768	1,999
Earnings Applicable to Common Stock	$11,630	$45,941	$24,425

See Notes to Financial Statements.

NEW ORLEANS PUBLIC SERVICE INC.
STATEMENTS OF RETAINED EARNINGS

	For the Years Ended December 31,		
	1994	1993	1992
		(In Thousands)	
Retained Earnings, January 1	$100,556	$98,560	$106,341
Add:			
Net income	13,211	47,709	26,424
Total	113,767	146,269	132,765
Deduct:			
Dividends declared:			
Preferred stock	1,536	1,768	1,999
Common stock	33,300	43,900	32,154
Capital stock expenses	45	45	52
Total	34,881	45,713	34,205
Retained Earnings, December 31 (Note 7)	$78,886	$100,556	$98,560

See Notes to Financial Statements.

NEW ORLEANS PUBLIC SERVICE INC.

MANAGEMENT'S FINANCIAL DISCUSSION AND ANALYSIS

RESULTS OF OPERATIONS

Net Income

Net income decreased in 1994 due primarily to the effects of the 1994 NOPSI Settlement (see Note 2) and the one-time recording of the cumulative effect of the change in accounting principle for unbilled revenues in 1993, partially offset by lower operating expenses. Net income increased in 1993 due primarily to the one-time recording of the cumulative effect of the change in accounting principle for unbilled revenues (see Note 1) and its ongoing effects, partially offset by the effect of implementing SFAS 106 (see Note 9). Effective January 1, 1993, NOPSI began accruing as revenues the charges for energy delivered to customers but not yet billed. Electric and gas revenues were previously recorded on a cycle-billing basis. Excluding the above mentioned items, net income for 1993 would have been $37.8 million. This $11.4 million increase is due primarily to increased gas revenues and increased electric retail energy sales.

Significant factors affecting the results of operations and causing variances between the years 1994 and 1993, and 1993 and 1992, are discussed under "Revenues and Sales" and "Expenses" below.

Revenues and Sales

See "Selected Financial Data-Five-Year Comparison," following the notes, for information on electric operating revenues by source and KWH sales.

Electric operating revenues decreased in 1994 due primarily to the effects of the 1994 NOPSI Settlement as discussed in Note 2. Electric energy sales increased slightly in 1994. Electric operating revenues were higher in 1993 due primarily to increased fuel adjustment revenues and increased collections of previously deferred Grand Gulf 1-related costs, neither of which affects net income, and increased residential energy sales resulting primarily from a return to more normal weather as compared to milder weather in 1992.

Gas operating revenues decreased slightly in 1994 as a result of lower gas sales. Gas operating revenues increased in 1993 due primarily to an increase in gas rates and increased fuel adjustment revenues resulting from higher average per unit cost for gas purchased.

Expenses

Operating expenses decreased in 1994 due primarily to lower purchased power expense and lower income tax expense. Operating expenses increased in 1993 due primarily to higher fuel expenses, higher income tax expense, and increased amortization of rate deferrals.

Purchased power expense decreased in 1994 due primarily to changes in generation availability and requirements among the System operating companies and lower costs. Fuel for electric generation and fuel-related expenses increased in 1993 due primarily to increased gas costs and increased generation requirements resulting primarily from increased energy sales as discussed in "Revenues and Sales" above.

Gas purchased for resale decreased in 1994 due to decreased gas sales. Gas purchased for resale increased in 1993 due primarily to a higher average per unit cost for gas purchased.

Income taxes decreased in 1994 due primarily to lower pretax income, resulting from the 1994 NOPSI Settlement, and the write-off of the unamortized balances of deferred investment tax credits pursuant to the FERC Settlement. Total income taxes increased in 1993 due primarily to higher pretax income and an increase in the federal income tax rate as a result of OBRA.

The increases in the amortization of rate deferrals in 1994 and 1993 is primarily a result of the collection of larger amounts of previously deferred costs under the 1991 NOPSI Settlement, which allowed NOPSI to record an additional $90 million of previously incurred Grand Gulf 1-related costs.

Competition

The electric utility industry is becoming increasingly competitive and NOPSI is seeking to become a leading competitor in the changing electric energy business. Competition presents NOPSI with many challenges. The following have been identified by NOPSI as its major competitive challenges.

Retail and Wholesale Rate Issues

Increasing competition in the utility industry brings an increased need to stabilize or reduce retail rates. In connection with the Merger, NOPSI agreed with the Council to reduce its annual electric base rates by $4.8 million effective for bills rendered on or after November 1, 1993. As a result of the 1994 NOPSI Settlement discussed in Note 2, NOPSI agreed to reduce electric and gas rates and issue credits and refunds to customers. Effective January 1, 1995, NOPSI implemented a $31.8 million permanent reduction in electric base rates and a $3.1 million permanent reduction in gas base rates. These adjustments resolved issues associated with NOPSI's return on equity exceeding 13.76% for the test year ended September 30, 1994. Under the 1991 NOPSI Settlement, NOPSI is recovering from its retail customers its allocable share of certain costs related to Grand Gulf 1. NOPSI's base rates to recover those costs were derived from estimates of those costs made at that time. Any overrecovery of costs is required to be returned to customers. Grand Gulf 1 has experienced lower operating costs than previously estimated, and NOPSI accordingly is reducing its base rates in two steps to more accurately match the current costs related to Grand Gulf 1. On January 1, 1995, NOPSI implemented a $10 million permanent reduction in base electric rates to reflect the reduced costs related to Grand Gulf 1, to be followed by an additional $4.4 million rate reduction on October 31, 1995. These Grand Gulf 1 rate reductions, which are expected to be largely offset by lower operating costs, may reduce NOPSI's after-tax net income by approximately $1.4 million per year beginning November 1, 1995. The next scheduled Grand Gulf 1 phase-in rate increase in the amount of $4.4 million on October 31, 1995, will not be affected by the 1994 NOPSI Settlement.

The 1994 NOPSI Settlement also requires NOPSI to credit its customers $25 million over a 21-month period beginning January 1, 1995, in order to resolve disputes with the Council regarding the interpretation of the 1991 NOPSI Settlement. NOPSI reduced its revenues and recorded a $15.4 million net-of-tax reserve associated with the credit in the fourth quarter of 1994. The 1994 NOPSI Settlement further required NOPSI to refund, in December 1994, $13.3 million of credits previously scheduled to be made to customers during the period January 1995 through July 1995. These credits were associated with a July 7, 1994, Council resolution that ordered a $24.95 million rate reduction based on NOPSI's overearnings during the test year ended September 30, 1993. Accordingly, NOPSI recorded an $8 million net-of-tax charge in the fourth quarter of 1994.

Retail wheeling, the transmission by an electric utility of energy produced by another entity over the utility's transmission and distribution system to a retail customer in the electric utility's area of service, is also evolving. Over a dozen states have been or are studying the concept of retail competition. In April 1994, the state of Michigan initiated a five-year experiment that allows limited competition among public utilities. During the same month, the California Public Utilities Commission proposed to deregulate that state's electric power industry, starting on January 1, 1996, to allow the largest industrial customers to select the lowest cost supplier for electricity service. Under the proposal, by the year 2002, smaller companies and residential customers in California would also be able to buy power from any suppliers. The California Public Utilities Commission is currently reviewing its proposal and is expected to make a ruling in the first half of 1995. The retail market for electricity is expected to become more competitive with such moves toward deregulation.

In some areas of the country, municipalities (or comparable entities) whose residents are served at retail by an investor-owned utility pursuant to a franchise are exploring the possibility of establishing new or extending existing distribution systems or seeking new delivery points in order to serve retail customers, especially large industrial customers, that currently receive service from an investor-owned utility. These options depend on the terms of a utility's franchise as well as on state law and regulation. In addition, FERC's authority to order utilities to transmit for a new or expanding municipal system is limited in certain respects. Where successful, however, the establishment of a municipal system or the acquisition by a municipal system of a utility's customers could result in the inability to recover costs that the utility has incurred in serving those customers.

In mid-1994, the FERC issued a notice of proposed rulemaking concerning a regulatory framework for dealing with recovery of stranded costs, such as high cost nuclear generating units, which may be incurred by electric utilities as a result of increased competition. In addition to addressing recovery of stranded costs related to wholesale service, the proposal requested comment as to recovery of retail stranded costs in transmission rates where state regulatory authorities failed to address the issue or were in conflict. Comments and reply comments have been filed, and the matter is pending. The risk of exposure to stranded costs which may result from competition in the industry will depend on the extent and timing of retail competition, the resolution of jurisdictional issues concerning stranded cost recovery, and the extent to which such costs are recovered from departing or remaining customers, among other matters.

In the wholesale rate area, FERC approved in 1992, with certain modifications, the proposal of AP&L, LP&L, MP&L, NOPSI, and Entergy Power to sell wholesale power at market-based rates and to provide to electric utilities "open access" to the System's transmission system (subject to certain requirements). GSU was later added to this filing. On October 31, 1994, as amended on January 25, 1995, Entergy Services filed with FERC revised transmission tariffs intended to provide access to transmission service on the same or comparable basis, terms, and conditions as the System operating companies, and the matter is pending. Open access and market pricing, once in effect, will increase marketing opportunities for NOPSI, but will also expose NOPSI to the risk of loss of load or reduced revenues due to competition with alternative suppliers.

In light of the rate issues discussed above, NOPSI is aggressively reducing costs to avoid potential earnings erosions that might result as well as to become more competitive. In 1994, NOPSI announced a restructuring program related to certain of its operating units. This program is designed to reduce costs and improve operating efficiencies. See Note 12 for further information. Also, in response to an increasingly competitive environment, NOPSI announced intentions to revise its initial least cost planning activities.

The Energy Policy Act of 1992

The EPAct addresses a wide range of energy issues and is altering the way Entergy and the rest of the electric utility industry operate. The EPAct encourages competition and affords utilities the opportunities, and the risks, associated with an open and more competitive market environment. The EPAct creates exemptions from regulation under the Holding Company Act and creates a class of exempt wholesale generators consisting of utility affiliates and nonutilities that are owners and operators of facilities for the generation and transmission of power for sales at wholesale. The EPAct also gives FERC the authority to order investor-owned utilities, including NOPSI, to transmit power and energy to or for wholesale purchasers and sellers. The law creates the potential for electric utilities and other power producers to gain increased access to the transmission systems of other entities to facilitate wholesale sales. Both NOPSI and Entergy Power expect to compete in this market. In addition, the EPAct allows utilities to own and operate foreign generation, transmission, and distribution facilities.

Litigation and Regulatory Proceedings

In November 1994, FERC approved an agreement settling a long-standing dispute involving income tax allocation procedures of System Energy. In accordance with the agreement, System Energy refunded approximately $10.5 million to NOPSI, which in turn made refunds on December 31, 1994, to customers. Additionally, System Energy will refund a total of approximately $10.5 million, plus interest, to NOPSI over the period through June 2004. The settlement also required the write-off of approximately $1.7 million of certain unamortized deferred investment tax credits by NOPSI.

Accounting Issues

Proposed Accounting Standards - The FASB has proposed a SFAS on "Accounting for the Impairment of Long-Lived Assets," effective January 1, 1996. The proposed standard describes circumstances which may result in assets being impaired and provides criteria for recognition and measurement of asset impairment. Certain operations of NOPSI are potentially affected by this standard, and any resulting write-offs will depend on future operating costs, generating units' efficiency and availability, and the future market for energy over the remaining life of the units. Based on current estimates, NOPSI anticipates that future revenues will fully recover the costs of such operations.

Continued Application of SFAS 71 - NOPSI's financial statements currently reflect assets and costs based on current cost-based ratemaking regulations, in accordance with SFAS 71, "Accounting for the Effects of Certain Types of Regulation." As discussed above, the electric utility industry is changing and these changes could possibly result in the discontinuance of the application of SFAS 71, which would result in the elimination of regulatory assets and liabilities. See Note 1 for further information.

NOTE 1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

NOPSI maintains accounts in accordance with FERC and other regulatory guidelines. Certain previously reported amounts have been reclassified to conform to current classifications.

Revenues and Fuel Costs

Prior to January 1, 1993, NOPSI recorded revenues when billed to its customers with no accrual for energy delivered but not yet billed. To provide a better matching of revenues and expenses, effective January 1, 1993, NOPSI adopted a change in accounting principle to provide for accrual of the nonfuel portion of estimated unbilled revenues. The cumulative effect of this accounting change as of January 1, 1993 increased net income by $10.9 million. Had this new accounting method been in effect during prior years, net income before the cumulative effect would not have been materially different from that shown in the accompanying financial statements.

NOPSI's rate schedules include electric fuel adjustment and gas cost adjustment clauses that allow deferral of fuel costs until such costs are reflected in the related revenues.

Utility Plant

Utility plant is stated at original cost. The original cost of utility plant retired or removed, plus the applicable removal costs, less salvage, is charged to accumulated depreciation. Maintenance, repairs, and minor replacement costs are charged to operating expenses. Substantially all of NOPSI's utility plant is subject to the liens of its mortgage bond indentures.

Total NOPSI net electric utility plant in service of $205 million as of December 31, 1994 includes $26 million of production plant, $20 million of transmission plant, $141 million of distribution plant, and $18 million of other plant. Total net gas utility plant of $66 million as of December 31, 1994 is primarily comprised of $60 million of distribution plant.

Depreciation is computed on the straight-line basis at rates based on the estimated service lives and costs of removal of the various classes of property. Depreciation provisions on average depreciable property approximated 3.1% in 1994, 1993, and 1992.

AFUDC represents the approximate net composite interest cost of borrowed funds and a reasonable return on the equity funds used for construction. Although AFUDC increases utility plant and increases earnings, it is only realized in cash through depreciation provisions included in rates. NOPSI's effective composite rates for AFUDC were 10.4%, 11.4%, and 12.1% for 1994, 1993, and 1992, respectively.

Income Taxes

NOPSI, its parent, and affiliates file a consolidated federal income tax return. Income taxes are allocated to NOPSI in proportion to its contribution to consolidated taxable income. SEC regulations require that no Entergy Corporation subsidiary pay more taxes than it would have had a separate income tax return been filed. Deferred taxes are recorded for all temporary differences between book and taxable income. Investment tax credits are deferred and amortized based upon the average useful life of the related property in accordance with rate treatment. As discussed in Note 3, in 1993 NOPSI changed its accounting for income taxes to conform with SFAS 109.

Other Noncurrent Liabilities

NOPSI records provisions for uninsured risks and claims for injuries and damages through charges to operations expenses on an accrual basis. Provisions for these accruals, classified as other noncurrent liabilities, have been allowed for ratemaking purposes.

Cash and Cash Equivalents

NOPSI considers all unrestricted highly liquid debt instruments purchased with an original maturity of three months or less to be cash equivalents.

Continued Application of SFAS 71

As a result of the EPAct and actions of regulatory commissions, the electric utility industry is moving toward a combination of competition and a modified regulatory environment. NOPSI's financial statements currently reflect assets and costs based on current cost-based ratemaking regulations in accordance with SFAS 71, "Accounting for the Effects of Certain Types of Regulation." Continued applicability of SFAS 71 to NOPSI's financial statements requires that rates set by an independent regulator on a cost of service basis (including a reasonable rate of return on invested capital) can actually be charged to and collected from customers.

In the event that either all or a portion of a utility's operations cease to meet those criteria for various reasons, including deregulation, a change in the method of regulation or a change in the competitive environment for the utility's regulated services, the utility should discontinue application of SFAS 71 for the relevant portion. That discontinuation should be reported by elimination from the balance sheet of the effects of any actions of regulators recorded as regulatory assets and liabil[illegible].

As of December 31, 1994, and for the foreseeable future, NOPSI's financial statements continue to follow SFAS 71.

Fair Value Disclosure

The estimated fair value of financial instruments has been determined by NOPSI, using available market information and appropriate valuation methodologies. However, considerable judgment is required in developing the estimates of fair value. Therefore, estimates are not necessarily indicative of the amounts that NOPSI could realize in a current market exchange. In addition, gains or losses realized on financial instruments may be reflected in future rates and not accrue to the benefit of stockholders.

NOPSI considers the carrying amounts of financial instruments classified as current assets and liabilities to be a reasonable estimate of their fair value because of the short maturity of these instruments. In addition, NOPSI does not presently expect that performance of its obligations will be required in connection with certain off-balance sheet commitments and guarantees considered financial instruments. Due to this factor, and because of the related party nature of these commitments and guarantees, determination of fair value is not considered practicable. See Notes 5 and 6 for additional fair value disclosure.

NOTE 2. RATE AND REGULATORY MATTERS

1994 NOPSI Settlement

In a settlement with the Council that was approved on December 29, 1994, NOPSI agreed to reduce electric and gas rates and issue credits and refunds to customers. Effective January 1, 1995, NOPSI implemented a $31.8 million permanent reduction in electric base rates and a $3.1 million permanent reduction in gas base rates. These adjustments resolved issues associated with NOPSI's return on equity exceeding 13.76% for the test year ended September 30, 1994. Under the 1991 NOPSI Settlement, NOPSI is recovering from its retail customers its allocable share of certain costs related to Grand Gulf 1. NOPSI's base rates to recover those costs were derived from estimates of those costs made at that time. Any overrecovery of costs is required to be returned to customers. Grand Gulf 1 has experienced lower operating costs than previously estimated, and NOPSI accordingly is reducing its base rates in two steps to more accurately match the current costs related to Grand Gulf 1. On January 1, 1995, NOPSI implemented a $10 million permanent reduction in base electric rates to reflect the reduced costs related to Grand Gulf 1, to be followed by an additional $4.4 million rate reduction on October 31, 1995. These Grand Gulf rate reductions, which are expected to be largely offset by lower operating costs, may reduce NOPSI's after-tax net income by approximately $1.4 million per year beginning November 1, 1995. The next scheduled Grand Gulf 1 phase-in rate increase in the amount of $4.4 million on October 31, 1995 will not be affected by the 1994 NOPSI Settlement.

The 1994 NOPSI Settlement also requires NOPSI to credit its customers $25 million over a 21-month period beginning January 1, 1995, in order to resolve disputes with the Council regarding the interpretation of the 1991 NOPSI Settlement. NOPSI reduced its revenues by $25 million and recorded a $15.4 million net-of-tax reserve associated with the credit in the fourth quarter of 1994. The 1994 NOPSI Settlement further required NOPSI to refund, in December 1994, $13.3 million of credits previously scheduled to be made to customers during the period January 1995 through July 1995. These credits were associated with a July 7, 1994, Council resolution that ordered a $24.95 million rate reduction based on NOPSI's overearnings during the test year ended September 30, 1993. Accordingly, NOPSI recorded an $8 million net-of-tax charge in the fourth quarter of 1994.

The 1994 NOPSI Settlement also required NOPSI to refund $9.3 million of overcollections associated with Grand Gulf 1 operating costs, and $10.5 million of refunds associated with the settlement by System Energy of a FERC tax audit. The settlement of the FERC tax audit by System Energy required refunds to be passed on to NOPSI and to other Entergy subsidiaries and then on to customers. These refunds have no effect on current period net income.

Merger - Related Rate Agreement

In 1993, the Council adopted resolutions accepting a proposal by NOPSI to settle certain issues related to the Merger. Pursuant to the resolutions, the Council agreed to withdraw from the SEC proceeding related to the Merger. In return NOPSI agreed, among other things, that retail ratepayers in the City of New Orleans would be protected from (1) increases in NOPSI's cost of capital resulting from risks associated with the Merger; (2) recovery of any portion of the acquisition premium or transactional costs associated with the Merger; (3) certain direct allocations of costs associated with GSU's River Bend nuclear unit; and (4) any losses of GSU resulting from resolution of litigation in connection with its ownership of River Bend. NOPSI was required to reduce its annual electric base rates by $4.8 million effective for bills rendered on or after November 1, 1993, and to expense its SFAS 106 costs. NOPSI's SFAS 106 expenses through October 31, 1996, will be allowed by the Council for purposes of evaluating the appropriateness of NOPSI's rates. The Council also agreed not to seek to disallow the first $3.5 million of costs incurred through October 31, 1993, in connection with the Least Cost Plan.

Prudence Settlement and Finalized Phase-In Plan

The February 4 Resolution required NOPSI to write off, and not recover from its retail electric customers, $135 million of its previously deferred costs associated with Grand Gulf 1. This write-off, which was recorded in NOPSI's 1987 financial statements, was in addition to the $51.2 million of Grand Gulf 1-related costs originally absorbed and not recovered by NOPSI as part of the 1986 Rate Settlement. In 1991, NOPSI reached a settlement (1991 NOPSI Settlement) with the Council and with the Alliance that resolved the Grand Gulf 1 prudence issues and the pending litigation related to the February 4 Resolution.

The 1991 NOPSI Settlement supersedes both the 1986 Rate Settlement (which established a rate phase-in plan designed to reduce the immediate effect on ratepayers of the inclusion of Grand Gulf 1 costs in rates) and the February 4 Resolution, and provides that there will be no further disallowance of the recovery of any Grand Gulf 1-related costs incurred by NOPSI based on any alleged imprudence by NOPSI that may have occurred or may be alleged to have occurred prior to the effective date of the 1991 NOPSI Settlement. The 1991 NOPSI Settlement included a rate decrease in 1991, followed by a series of rate increases. The last of the rate increases will become effective on October 31, 1995, in the amount of $4.4 million.

In connection with the rate changes, NOPSI implemented a finalized phase-in plan, covering a ten-year period from October 1, 1991 through September 30, 2001, for recovery of all Grand Gulf 1 deferred costs, including associated carrying charges.

NOPSI agreed to a five-year electric base rate freeze extending through October 31, 1996, excluding the annual rate increases provided for above and except for increases to reflect an increase in state and/or federal income tax rates or a catastrophic event such as a hurricane. NOPSI also agreed that during the period October 1, 1992 through October 31, 1996 the Council will have the right to investigate the appropriateness of NOPSI's rates if NOPSI's return on average equity on its electric operations (calculated in accordance with the applicable provisions of the 1991 NOPSI Settlement) for twelve month periods subsequent to September 30, 1992 were to exceed 13.76%, and, after hearing(s), to impose a credit on NOPSI's customers' bills in an amount that would have allowed NOPSI, during the relevant test year, to earn a return on equity incident to its electric operations of no less than 12.76% (see discussion below). The Council agreed otherwise not to reduce NOPSI's base electric rates during the period through October 31, 1996 except to reflect a decrease in state and/or federal income tax rates; however, this was amended by the 1994 NOPSI Settlement discussed above.

NOPSI will include in the "over/under" provision of its fuel adjustment clause on a monthly basis the difference, if any, between the non-fuel Grand Gulf 1 costs billed by System Energy to NOPSI and the estimate of such costs attached to the 1991 NOPSI Settlement, with the Council having the right to suspend this provision in the event of a catastrophe involving Grand Gulf 1. In the event the Council suspends this provision, NOPSI will have the right to seek a rate increase notwithstanding the five-year electric base rate freeze discussed above. In addition, the 1994 NOPSI Settlement now requires interest to be included in the "over/under" provision.

Gas Rate Filing

In May 1992, NOPSI and the Council reached a settlement regarding NOPSI's application for an increase in gas rates. The settlement includes the following terms, among others:

(i) an aggregate net rate increase of $7.5 million, effective on May 22, 1992, phased in over a two-year period. The year one net increase is stipulated to be $3.8 million, with an additional $3.0 million

being deferred for recovery in equal annual installments in years two through six. The net increase in year two of $3.7 million includes $730,000 for recovery of the costs deferred in year one (including associated carrying charges).

(ii) except as provided above, and except for increases to reflect an increase in state and/or federal income tax rates or a catastrophic event such as a hurricane, NOPSI has agreed to a gas base rate freeze through October 31, 1996; however, this was amended by the 1994 NOPSI Settlement discussed above.

In addition, the settlement provides that earnings from gas operations will be included with those from electric operations for purposes of the return on average equity ceiling provisions of the 1991 NOPSI Settlement (discussed above) and revises the method of calculating such return on equity ceiling.

NOTE 3. INCOME TAXES

Income tax expense consisted of the following:

	For the Years Ended December 31,		
	1994	1993	1992
	(In Thousands)		
Current:			
Federal	$ 19,557	$ 23,400	$ 16,575
State	3,049	4,079	-
Total	22,606	27,479	16,575
Deferred - net:			
Rate deferrals - net	(6,325)	(7,395)	(1,185)
Net operating loss carryforward utilization	-	42	2,747
Unbilled revenue	2,761	4,621	(2,800)
Pension expense	1,308	2,935	(1,044)
Liberalized depreciation	841	(19)	(286)
Deferred fuel or gas costs	(2,104)	2,251	1,904
Bond reacquisition	165	1,074	328
Alternative minimum tax	1,116	2,317	(3)
Rate refund	(9,620)	-	-
Severance accrual	(1,518)	-	-
Other	(2,298)	(623)	(1)
Total	(15,674)	5,203	(340)
Investment tax credit adjustments - net	(681)	(743)	(170)
Investment tax credit amortization - FERC settlement	(1,651)	-	-
Recorded income tax expense	$ 4,600	$ 31,939	$ 16,065
Charged to operations	$ 3,602	$ 24,232	$ 14,382
Charged to other income	998	1,115	1,683
Charged to cumulative effect	-	6,592	-
Total income taxes	$ 4,600	$ 31,939	$ 16,065

Total income taxes differ from the amounts computed by applying the statutory federal income tax rate to income before taxes. The reasons for the differences were:

	For the Years Ended December 31,					
	1994		1993		1992	
	Amount	% of Pretax Income	Amount	% of Pretax Income	Amount	% of Pretax Income
	(Dollars in Thousands)					
Computed at statutory rate	$ 6,234	35.0	$27,877	35.0	$14,446	34.0
Increases (reductions) in tax resulting from:						
State income taxes net of federal income tax effect	456	2.6	3,411	4.3	1,462	3.5
Depreciation	(586)	(3.3)	(780)	(1.0)	(731)	(1.7)
Amortization of investment tax credits	(681)	(3.8)	(745)	(0.9)	(752)	(1.8)
Investment tax credit amortization - FERC settlement	(1,651)	(9.2)				
Amortization of excess deferred income tax	714	4.0	384	0.5	376	0.9
Adjustment of prior year taxes	(423)	(2.4)	2,413	3.0	391	0.9
SFAS 109 adjustment	-	-	(1,170)	(1.5)	-	-
Other - net	537	3.0	549	0.7	873	2.0
Total income taxes	$ 4,600	25.9	$31,939	40.1	$16,065	37.8

Significant components of NOPSI's net deferred tax liabilities as of December 31, 1994 and 1993, were:

	1994	1993
	(In Thousands)	
Deferred tax liabilities:		
Net regulatory assets	$ (12,946)	$ (13,465)
Plant related basis differences	(50,624)	(49,753)
Rate deferrals	(74,054)	(80,380)
Other	(3,303)	(5,194)
Total	$(140,927)	$(148,792)
Deferred tax assets:		
Unbilled revenues	$ 3,051	$ 5,812
Accumulated deferred investment tax credit	4,154	4,460
Pension related items	4,497	5,804
Removal cost	9,146	8,197
Standard coal plant	2,783	2,861
Operating reserves	6,665	6,934
Rate refund	9,620	-
Other	6,840	4,660
Total	$ 46,756	$ 38,728
Net deferred tax liabilities	$ (94,171)	$(110,064)

In accordance with a System Energy FERC settlement, NOPSI wrote off $1.7 million of unamortized deferred investment tax credits in 1994.

In 1993, NOPSI adopted SFAS 109. SFAS 109 required that deferred income taxes be recorded for all temporary differences and carryforwards, and that deferred tax balances be based on enacted tax laws at tax rates that are expected to be in effect when the temporary differences reverse. SFAS 109 required that regulated enterprises recognize adjustments resulting from implementation as regulatory assets or liabilities if it is probable that such amounts will be recovered from or returned to customers in future rates. A substantial majority of the adjustments required by SFAS 109 was recorded to deferred tax balance sheet accounts with offsetting adjustments to regulatory assets and liabilities. As a result of the adoption of SFAS 109, 1993 net income was increased by $0.3 million, assets were increased by $4.1 million, and liabilities were increased by $3.8 million. The cumulative effect of the adoption of SFAS 109 is included in income tax expense charged to operations.

NOTE 4. LINES OF CREDIT AND RELATED BORROWINGS

The SEC has authorized NOPSI to effect short-term borrowings of up to $39 million. This authorization is effective through November 30, 1996. In addition, NOPSI can borrow from the Money Pool, subject to its maximum authorized level of short-term borrowings and the availability of funds. NOPSI's short-term borrowings are also limited by the terms of its G&R Bond indenture to amounts not exceeding, in general, the greater of 10% of capitalization or 50% of Grand Gulf 1 rate deferrals available to support the issuance of G&R Bonds. NOPSI had no outstanding borrowings under these arrangements as of December 31, 1994.

NOTE 5. PREFERRED STOCK

The number of shares and dollar value of NOPSI's cumulative, $100 par value preferred stock were:

	As of December 31,				
	Shares Authorized and Outstanding		Total Dollar Value		Call Price Per Share as of December 31,
	1994	1993	1994	1993	1994
			(Dollars in Thousands)		
Without sinking fund:					
4 3/4% Preferred Stock	77,798	77,798	$ 7,780	$ 7,780	$105.00
4.36% Series	60,000	60,000	6,000	6,000	$104.58
5.56% Series	60,000	60,000	6,000	6,000	$102.59
Total without sinking fund	197,798	197,798	$19,780	$19,780	
With sinking fund:					
15.44% Series	34,495	49,495	$ 3,450	$ 4,950	$107.72

The fair value of NOPSI's preferred stock with sinking fund was estimated to be approximately $3.6 million and $5.3 million as of December 31, 1994 and 1993, respectively. The fair values were determined using quoted market prices or estimates from nationally recognized investment banking firms. See Note 1 for additional information on disclosure of fair value of financial instruments.

Changes in the preferred stock during the last three years were:

	Number of Shares		
	1994	1993	1992
Preferred stock retirements:			
$100 par value	(15,000)	(15,000)	(15,000)

Cash sinking fund requirements for the next five years for preferred stock outstanding as of December 31, 1994, are (in millions) 1995 - $1.5; 1996 - $0.75; 1997 - $0.75 and 1998 - $0.45. NOPSI has the annual non-cumulative option to redeem, at par, up to an additional $750,000 of its 15.44% Series preferred stock outstanding.

NOTE 6. LONG-TERM DEBT

NOPSI's long-term debt as of December 31, 1994 and 1993, was:

Maturities		Interest Rates			
From	To	From	To	1994	1993
				(In Thousands)	
First Mortgage Bonds					
1995	1998	5-5/8%	5-7/8%	$ 35,250	$ 35,250
G&R Bonds					
1995	1998	10.95%	13.9%	54,200	69,200
1999	2023	7.0%	8.0%	100,000	100,000
Unamortized Premium and Discount-Net				(1,090)	(1,138)
Total Long-Term Debt				188,360	203,312
Less Amount Due Within One Year				24,200	15,000
Long-Term Debt Excluding Amount Due Within One Year				$ 164,160	$ 188,312

The fair value of NOPSI's long-term debt as of December 31, 1994 and 1993 was estimated to be $178.7 million and $211.5 million, respectively. Fair values were determined using bid prices reported by dealer markets and by nationally recognized investment banking firms. See Note 1 for additional information on disclosure of fair value of financial instruments.

For the years 1995, 1996, 1997 and 1998, NOPSI has long-term debt maturities of (in millions) $24.2, $38.3, $27 and $0, respectively. In addition, other sinking fund requirements of approximately $0.4 million and $0.1 million for 1995 and 1996, respectively, may be satisfied by cash or by certification of property additions at the rate of 167% of such requirements.

Under NOPSI's G&R Mortgage, G&R Bonds are issuable based upon 70% of bondable property additions or based upon 50% of accumulated deferred Grand Gulf 1-related costs. The G&R Mortgage precludes the issuance of any additional bonds based upon property additions if the total amount of outstanding Rate Recovery Mortgage Bonds issued on the basis of the uncollected balance of deferred Grand Gulf 1-related costs exceeds 66 2/3% of the balance of such deferred costs. As of December 31, 1994, the total amount of Rate Recovery Mortgage Bonds outstanding aggregated $54.2 million, or 26.5% of NOPSI's accumulated deferred Grand Gulf 1-related costs.

NOTE 7. DIVIDEND RESTRICTIONS

NOPSI's Restatement of Articles of Incorporation, as amended, and certain of its indentures contain provisions restricting the payment of cash dividends or other distributions on common stock. As of December 31, 1994, $24.2 million of NOPSI's retained earnings were restricted against the payment of cash dividends or other distributions on common stock.

NOTE 8. COMMITMENTS AND CONTINGENCIES

Capital Requirements and Financing

Construction expenditures for the years 1995, 1996, and 1997 are estimated to total $28.6 million each year. NOPSI will also require $92.5 million during the period 1995-1997 to meet long-term debt and preferred stock maturities and cash sinking fund requirements. NOPSI plans to meet the above requirements with internally generated funds, cash on hand, and the issuance of long-term debt. See Notes 5 and 7 regarding the possible refinancing, redemption, purchase, or other acquisition of certain outstanding series of preferred stock and long-term debt.

Unit Power Sales Agreement

System Energy has agreed to sell all of its 90% owned and leased share of capacity and energy from Grand Gulf 1 to AP&L, LP&L, MP&L, and NOPSI in accordance with specified percentages (AP&L 36%, LP&L 14%, MP&L 33%, and NOPSI 17%) as ordered by FERC. Charges under this agreement are paid in consideration for NOPSI's respective entitlement to receive capacity and energy, and are payable irrespective of the quantity of energy delivered so long as the unit remains in commercial operation. The agreement will remain in effect until terminated by the parties and approved by FERC, most likely upon Grand Gulf 1's retirement from service. NOPSI's monthly obligation for payments under the agreement is approximately $8 million.

Availability Agreement

AP&L, LP&L, MP&L, and NOPSI are individually obligated to make payments or subordinated advances to System Energy in accordance with stated percentages (AP&L 17.1%, LP&L 26.9%, MP&L 31.3%, and NOPSI 24.7%) in amounts that when added to amounts received under the Unit Power Sales Agreement or otherwise, are adequate to cover all of System Energy's operating expenses. System Energy has assigned its rights to payments and advances to certain creditors as security for certain obligations. Since commercial operation of Grand Gulf 1, payments under the Unit Power Sales Agreement have exceeded the amounts payable under the Availability Agreement. Accordingly, no payments have ever been required. If AP&L, LP&L, or MP&L fails to make its Unit

Power Sales Agreement payments, and System Energy is unable to obtain funds from other sources, NOPSI could be liable for payments to System Energy, in amounts that cannot be determined, over and above its payments under the Unit Power Sales Agreement.

Reallocation Agreement

System Energy and AP&L, LP&L, MP&L, and NOPSI entered into the Reallocation Agreement relating to the sale of capacity and energy from the Grand Gulf Station and the related costs, in which LP&L, MP&L, and NOPSI agreed to assume all of AP&L's responsibilities and obligations with respect to the Grand Gulf Station under the Availability Agreement. FERC's decision allocating a portion of Grand Gulf 1 capacity and energy to AP&L supersedes the Reallocation Agreement as it relates to Grand Gulf 1. Responsibility for any Grand Gulf 2 amortization amounts has been individually allocated (LP&L 26.22%, MP&L 43.97%, and NOPSI 29.80%) under the terms of the Reallocation Agreement. However, the Reallocation Agreement does not affect AP&L's obligation to System Energy's lenders under the assignments referred to in the preceding paragraph. AP&L would be liable for its share of such amounts if LP&L, MP&L, and NOPSI were unable to meet their contractual obligations. No payments of any amortization amounts will be required as long as amounts paid to System Energy under the Unit Power Sales Agreement, including other funds available to System Energy, exceed amounts required under the Availability Agreement, which is expected to be the case for the foreseeable future.

System Fuels

NOPSI has a 13% interest in System Fuels, a jointly owned subsidiary of AP&L, LP&L, MP&L, and NOPSI. The parent companies of System Fuels, including NOPSI, agreed to make loans to System Fuels to finance its fuel procurement, delivery, and storage activities. As of December 31, 1994, NOPSI had approximately $3.3 million of loans outstanding to System Fuels which mature in 2008.

City Franchise Ordinances

NOPSI provides electric and gas service in the City of New Orleans pursuant to City franchise ordinances that state, among other things, that the City has a continuing option to purchase NOPSI's electric and gas utility properties.

Sales/Use Tax Issues

In September 1994, the Louisiana Supreme Court (Court) issued an opinion (in a case in which none of the System companies was a party) holding, in part, that the Louisiana state legislature's suspension of state sales and use tax exemptions also had the effect of suspending exemptions from local sales and use taxes. On January 27, 1995 the Court, after rehearing, reversed its opinion. Because of the Court's most recent ruling, sales of electricity and gas, fuels and other items used by NOPSI to generate electricity in Louisiana, as well as others exempt from sales and use taxes, continue to be exempt from local sales and use taxes, even though the state exemptions for sales and use tax have been suspended.

NOTE 9. POSTRETIREMENT BENEFITS

Pension Plan

NOPSI is a participating employer in a defined benefit pension plan sponsored by LP&L, covering substantially all employees. The pension plan is noncontributory and provides pension benefits based on employees' credited service and average compensation, generally during the last five years before retirement. Pension costs are funded in accordance with contribution guidelines established by the Employee Retirement Income Security Act of 1974, as amended, and the Internal Revenue Code of 1986, as amended. The assets of the plan consist primarily of common and preferred stocks, fixed income securities, interest in a money market fund, and insurance contracts.

NOPSI's 1994, 1993, and 1992 pension cost, including amounts capitalized, included the following components:

	For the Years Ended December 31,		
	1994*	1993*	1992*
	(In Thousands)		
Service cost - benefits earned during the period	$ 1,502	$ 1,387	$1,253
Interest cost on projected benefit obligation	2,740	2,422	2,119
Net amortization and deferral	(970)	(49)	173
Net pension cost	$ 3,272	$ 3,760	$3,545

* Pension cost represents NOPSI's allocated portion of the total pension expense (as calculated by an independent actuary) for the defined benefit pension plan sponsored by LP&L.

The funded status of LP&L's pension plan allocable to NOPSI employees as of December 31, 1994 and 1993, was:

	1994	1993
	(In Thousands)	
Actuarial present value of accumulated pension plan benefits:		
Vested	$ 26,291	$ 26,173
Nonvested	41	36
Accumulated benefit obligation	$ 26,332	$ 26,209
Plan assets at fair value	$ 18,180	$ 7,523
Projected benefit obligation	33,738	36,831
Plan assets less than projected benefit obligation	(15,558)	(29,308)
Unrecognized prior service cost	2,291	2,462
Unrecognized transition asset	(1,159)	(1,354)
Unrecognized net loss	5,779	12,184
	(8,647)	(16,016)
Unfunded portion of NOPSI pension liability	1,584	12,256
Accrued pension liability	$ (7,063)	$ (3,760)

The significant actuarial assumptions used in computing the information above for 1994, 1993, and 1992 were as follows: weighted average discount rate, 8.5% for 1994, 7.5% for 1993 and 8.25% for 1992; weighted average rate of increase in future compensation levels, 5.1% for 1994 and 5.6% for 1993 and 1992; and expected long-term rate of return on plan assets, 8.5%. Transition assets are being amortized over the average remaining service period of active participants.

Other Postretirement Benefits

NOPSI also provides certain health care and life insurance benefits for retired employees. Substantially all employees may become eligible for these benefits if they reach retirement age while still working for NOPSI. The cost of providing these benefits, recorded on a cash basis, to retirees in 1992 was approximately $3.7 million. Prior to 1992, the cost of providing these benefits for retirees was not separable from the cost of providing benefits for active employees.

Effective January 1, 1993, NOPSI adopted SFAS 106. This standard requires a change from a cash method to an accrual method of accounting for postretirement benefits other than pensions. As of January 1, 1993, the actuarially determined accumulated postretirement benefit obligation (APBO) earned by retirees and active employees was estimated to be approximately $53.6 million. This obligation is being amortized over a 20-year period beginning in 1993.

NOPSI is expensing its SFAS 106 costs pursuant to resolutions adopted in November 1993 by the Council related to the Merger. NOPSI's SFAS 106 expenses through October 31, 1996, will be allowed by the Council for purposes of evaluating the appropriateness of NOPSI's rates. Furthermore, due to the Council resolutions, NOPSI has established and commenced funding a Voluntary Employee's Beneficiary Association (VEBA) trust. During 1994, NOPSI funded $6.8 million to the VEBA trust. The trusts assets are invested in a money market fund.

NOPSI's 1994 and 1993 postretirement benefit cost, including amounts capitalized and deferred, included the following components:

	1994	1993
	(In Thousands)	
Service cost - benefits earned during the period	$ 813	$ 822
Interest cost on APBO	3,502	4,248
Net deferral and amortization	2,569	2,678
Net periodic postretirement benefit cost	$ 6,884	$ 7,748

The funded status of NOPSI's postretirement plan as of December 31, 1994 and 1993, was (in thousands):

	1994	1993
	(In Thousands)	
Accumulated postretirement benefit obligation:		
Retirees	$ 38,059	$ 46,218
Other fully eligible participants	3,351	3,565
Other active participants	3,551	9,152
	44,961	58,935
Plan assets at fair value	6,784	-
Plan assets less than APBO	(38,177)	(58,935)
Unrecognized transition obligation	48,217	50,895
Unrecognized net loss	(10,057)	4,835
Accrued post retirement benefit liability	$ (17)	$ (3,205)

The assumed health care cost trend rate used in measuring the APBO was 9.4% for 1995, gradually decreasing each successive year until it reaches 5.0% in 2011. A one percentage-point increase in the assumed health care cost trend rate for each year would have increased the APBO as of December 31, 1994, by 8.6% and the sum of the service cost and interest cost by approximately 10.0% The assumed discount rate and rate of increase in future compensation used in determining the APBO were 8.5% for 1994 and 7.5% for 1993 and 5.1%, for 1994 and 5.5% for 1993, respectively.

NOTE 10. TRANSACTIONS WITH AFFILIATES

NOPSI buys electricity from and/or sells electricity to the other System operating companies and System Energy under rate schedules filed with FERC. In addition, NOPSI purchases fuel from System Fuels and receives technical and advisory services from Entergy Services.

Operating revenues include revenues from sales to affiliates amounting to $2.1 million in 1994, $2.5 million in 1993, and $3.1 million in 1992. Operating expenses include charges from affiliates for fuel costs, purchased power and related charges, and technical and advisory services totaling $170.1 million in 1994, $176.3 million in 1993, and $183.0 million in 1992.

NOTE 11. BUSINESS SEGMENT INFORMATION

NOPSI supplies electric and natural gas services in the City. NOPSI's segment information follows:

	1994		1993		1992	
	Electric	Gas	Electric	Gas	Electric	Gas
			(In Thousands)			
Operating revenues	$ 360,430	$ 87,357	$423,830	$90,992	$391,936	$72,943
Revenue from sales to unaffiliated customers (1)	$ 358,369	$ 87,357	$421,343	$90,992	$388,851	$72,943
Operating income (loss) before income taxes	$ 23,976	$ 9,387	$ 72,572	$11,412	$ 63,167	$ 1,264
Operating income (loss)	$ 22,358	$ 7,403	$ 52,046	$ 7,706	$ 47,194	$ 2,855
Net utility plant	$ 209,901	$ 67,875	$211,776	$63,803	$206,402	$61,783
Depreciation expense	$ 15,743	$ 3,310	$ 14,308	$ 2,976	$ 13,776	$ 2,843
Construction expenditures	$ 16,997	$ 5,780	$ 19,774	$ 5,039	$ 15,724	$ 5,319

(1) NOPSI's intersegment transactions are not material (less than 1% of sales to unaffiliated customers).

NOTE 12. RESTRUCTURING COSTS

During the third quarter of 1994, NOPSI announced a restructuring program related to certain of its operating units. The program is designed to reduce costs, improve operating efficiencies, and increase shareholder value in order to enable NOPSI to become a low-cost producer. The program includes reductions in the number of employees and the consolidation of offices and facilities. In 1994, NOPSI recorded restructuring charges of $3.4 million. These charges primarily include employee severance costs related to the expected termination of approximately 146 employees. As of December 31, 1994, no employees have been terminated and no termination benefits have been paid under this restructuring program.

NOTE 13. QUARTERLY FINANCIAL DATA (UNAUDITED)

NOPSI's business is subject to seasonal fluctuations with the peak periods occurring during the third quarter for electric and during the first quarter for gas. Operating results for the four quarters of 1994 and 1993 were:

	Operating Revenues	Operating Income	Net Income (Loss)
		(In Thousands)	
1994:			
First Quarter	$117,088	$ 6,459	$ 1,813
Second Quarter	$124,402	$ 17,880	$ 13,812
Third Quarter	$133,574	$ 15,941	$ 11,933
Fourth Quarter	$ 72,723	$(10,519)	$ (14,347)
1993:			
First Quarter	$108,566	$ 8,828	$ 14,930
Second Quarter	$120,182	$ 17,789	$ 12,714
Third Quarter	$154,610	$ 29,648	$ 24,843
Fourth Quarter	$131,464	$ 3,487	$ (4,778)

See Note 2 for information regarding credits and refunds recorded in 1994 as a result of the 1994 NOPSI Settlement.

See Note 1 for information regarding the recording of the cumulative effect of the change in accounting principle for unbilled revenues in January 1993.

NEW ORLEANS PUBLIC SERVICE INC.

SELECTED FINANCIAL DATA - FIVE-YEAR COMPARISON

	1994	1993	1992	1991	1990
			(In Thousands)		
Operating revenues	$ 447,787	$ 514,822	$ 464,879	$ 476,165	$ 485,246
Income before cumulative effect of a change in accounting principle	$ 13,211	$ 36,761	$ 26,424	$ 74,699	$ 27,542
Total assets	$ 592,894	$ 647,605	$ 621,691	$ 685,217	$ 577,283
Long-term obligations (1)	$ 167,610	$ 193,262	$ 165,917	$ 231,901	$ 243,239

(1) Includes long-term debt (excluding currently maturing debt) and preferred stock with sinking fund.

See Notes 1, 3, and 9 for the effect of accounting changes in 1993.

	1994	1993	1992	1991	1990
			(Dollars in Thousands)		
Electric Operating Revenues:					
Residential	$142,013	$ 151,423	$ 137,668	$ 136,030	$ 141,900
Commercial	162,410	167,788	160,229	159,118	162,600
Industrial	25,422	26,205	23,860	24,062	27,000
Governmental	58,726	61,548	56,023	55,097	53,500
Total retail	388,571	406,964	377,780	374,307	385,000
Sales for resale	9,573	11,778	10,320	9,805	8,400
Other	(37,714)	5,088	3,836	15,102	3,900
Total	$360,430	$ 423,830	$ 391,936	$ 399,214	$ 397,300
Billed Electric Energy Sales (Millions of KWH):					
Residential	1,896	1,914	1,806	1,844	1,903
Commercial	2,031	1,989	1,977	2,023	2,054
Industrial	518	499	457	487	530
Governmental	951	924	888	887	846
Total retail	5,396	5,326	5,128	5,241	5,333
Sales for resale	294	351	405	418	294
Total	5,690	5,677	5,533	5,659	5,627

NOTE 13. QUARTERLY FINANCIAL DATA (UNAUDITED)

NOPSI's business is subject to seasonal fluctuations with the peak periods occurring during the third quarter for electric and during the first quarter for gas. Operating results for the four quarters of 1994 and 1993 were:

	Operating Revenues	Operating Income	Net Income (Loss)
		(In Thousands)	
1994:			
First Quarter	$117,08[illegible]	$ 6,459	$ 1,813
Second Quarter	$124,402	$ 17,880	$ 13,812
Third Quarter	$133,57[illegible]	$ 15,941	$ 11,933
Fourth Quarter	$ 72,723	$(10,519)	$(14,347)
1993:			
First Quarter	$108,56[illegible]	$ 8,828	$ 14,930
Second Quarter	$120,182	$ 17,789	$ 12,714
Third Quarter	$154,610	$ 29,648	$ 24,843
Fourth Quarter	$131,464	$ 3,487	$ (4,778)

See Note 2 for information regarding credits and refunds recorded in 1994 as a result of the 1994 NOPSI Settlement.

See Note 1 for information regarding the recording of the cumulative effect of the change in accounting principle for unbilled revenues in January 1993.

NEW ORLEANS PUBLIC SERVICE INC.

SELECTED FINANCIAL DATA - FIVE-YEAR COMPARISON

	1994	1993	1992	1991	1990
			(In Thousands)		
Operating revenues	$ 447,787	$ 514,822	$ 464,879	$ 476,165	$ 485,246
Income before cumulative effect of a change in accounting principle	$ 13,211	$ 36,761	$ 26,424	$ 74,699	$ 27,542
Total assets	$ 592,894	$ 647,605	$ 621,691	$ 685,217	$ 577,283
Long-term obligations (1)	$ 167,610	$ 193,262	$ 165,917	$ 231,901	$ 243,239

(1) Includes long-term debt (excluding currently maturing debt) and preferred stock with sinking fund.

See Notes 1, 3, and 9 for the effect of accounting changes in 1993.

	1994	1993	1992	1991	1990
			(Dollars in Thousands)		
Electric Operating Revenues:					
Residential	$142,013	$ 151,423	$ 137,668	$ 136,030	$ 141,900
Commercial	162,410	167,788	160,229	159,118	162,600
Industrial	25,422	26,205	23,860	24,062	27,000
Governmental	58,726	61,548	56,023	55,097	53,500
Total retail	388,571	406,964	377,780	374,307	385,000
Sales for resale	9,573	11,778	10,320	9,805	8,400
Other	(37,714)	5,088	3,836	15,102	3,900
Total	$360,430	$ 423,830	$ 391,936	$ 399,214	$ 397,300
Billed Electric Energy Sales (Millions of KWH):					
Residential	1,896	1,914	1,806	1,844	1,903
Commercial	2,031	1,989	1,977	2,023	2,054
Industrial	518	499	457	487	530
Governmental	951	924	888	887	846
Total retail	5,396	5,326	5,128	5,241	5,333
Sales for resale	294	351	405	418	294
Total	5,690	5,677	5,533	5,659	5,627



System Energy

SYSTEM ENERGY RESOURCES, INC.

DEFINITIONS

Certain abbreviations or acronyms used in System Energy's Financial Statements, Notes to Financial Statements, and Management's Financial Discussion and Analysis are defined below:

Abbreviation or Acronym	Term
AFUDC	Allowance for Funds Used During Construction
ALJ	Administrative Law Judge
AP&L	Arkansas Power & Light Company
APSC	Arkansas Public Service Commission
Capital Funds Agreement	Agreement, dated as of June 21, 1974, as amended, between System Energy and Entergy Corporation, and the assignments thereof
City of New Orleans or City	New Orleans, Louisiana
DOE	United States Department of Energy
Entergy Operations	Entergy Operations, Inc., a subsidiary of Entergy Corporation that has operating responsibility for Grand Gulf 1, Waterford 3, ANO, and River Bend
Entergy or System	Entergy Corporation and its various direct and indirect subsidiaries
Entergy Services	Entergy Services, Inc.
EPAct	The Energy Policy Act of 1992
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
FERC Complaint Case Settlement	Settlement, effective May 21, 1991, whereby System Energy credited approximately $47.6 million in the aggregate (including interest) against its June 1991 bills to AP&L, LP&L, MP&L, and NOPSI for capacity and energy from Grand Gulf 1
FERC Return on Equity Case	Settlement, effective October 25, 1993, whereby System Energy refunded approximately $29.6 million in the aggregate (including interest) against its October 1993 bills to AP&L, LP&L, MP&L, and NOPSI when FERC reduced System Energy's Return on Equity from 13% to 11% prospectively from November 3, 1992
Grand Gulf Station	Grand Gulf Steam Electric Generating Station (nuclear)
Grand Gulf 1	Unit No. 1 of the Grand Gulf Station (nuclear)
Grand Gulf 2	Unit No. 2 of the Grand Gulf Station (nuclear)

Abbreviation or Acronym	Term
GSU	Gulf States Utilities Company (including wholly owned subsidiaries - Varibus Corporation, GSG&T, Inc., Prudential Oil and Gas, Inc., and Southern Gulf Railway Company)
KWH	Kilowatt-Hours
LP&L	Louisiana Power & Light Company
LPSC	Louisiana Public Service Commission
Money Pool	Entergy Money Pool which allows certain System companies to borrow from, or lend to, certain other System companies
MP&L	Mississippi Power & Light Company
MPSC	Mississippi Public Service Commission
NOPSI	New Orleans Public Service Inc.
NRC	Nuclear Regulatory Commission
OBRA	Omnibus Budget Reconciliation Act of 1993
Reallocation Agreement	1981 Agreement, superseded in part by a June 13, 1985 decision of FERC, among AP&L, LP&L, MP&L, NOPSI, and System Energy relating to the sale of capacity and energy from the Grand Gulf Station
SEC	Securities and Exchange Commission
SFAS	Statement of Financial Accounting Standards promulgated by the FASB
SFAS 109	SFAS 109, "Accounting for Income Taxes"
SMEPA	South Mississippi Electric Power Association
System or Entergy	Entergy Corporation and its various direct and indirect subsidiaries
System Energy	System Energy Resources, Inc.
System Fuels	System Fuels, Inc.
System operating companies	AP&L, GSU, LP&L, MP&L, and NOPSI, collectively
Unit Power Sales Agreement	Agreement, dated as of June 10, 1982, as amended, among AP&L, LP&L, MP&L, NOPSI, and System Energy, relating to the sale of capacity and energy from System Energy's share of Grand Gulf 1

SYSTEM ENERGY RESOURCES, INC.

REPORT OF MANAGEMENT

The management of System Energy Resources, Inc. has prepared and is responsible for the financial statements and related financial information included herein. The financial statements are based on generally accepted accounting principles. Financial information included elsewhere in this report is consistent with the financial statements.

To meet its responsibilities with respect to financial information, management maintains and enforces a system of internal accounting controls that is designed to provide reasonable assurance, on a cost-effective basis, as to the integrity, objectivity, and reliability of the financial records, and as to the protection of assets. This system includes communication through written policies and procedures, an employee Code of Conduct, and an organizational structure that provides for appropriate division of responsibility and the training of personnel. This system is also tested by a comprehensive internal audit program.

The independent public accountants provide an objective assessment of the degree to which management meets its responsibility for fairness of financial reporting. They regularly evaluate the system of internal accounting controls and perform such tests and other procedures as they deem necessary to reach and express an opinion on the fairness of the financial statements.

Management believes that these policies and procedures provide reasonable assurance that its operations are carried out with a high standard of business conduct.

DONALD C. HINTZ
President and Chief Executive Officer

GERALD D. MCINVALE
Senior Vice President and
Chief Financial Officer

SYSTEM ENERGY RESOURCES, INC.

AUDIT COMMITTEE CHAIRMAN'S LETTER

The Entergy Corporation Board of Directors' Audit Committee functions as the Audit Committee for System Energy. The Audit Committee is comprised of four directors, who are not officers of System Energy: H. Duke Shackelford (Chairman), Lucie J. Fjeldstad, Dr. Norman C. Francis, and James R. Nichols. The committee held four meetings during 1994.

The Audit Committee oversees System Energy's financial reporting process on behalf of the Board of Directors and provides reasonable assurance to the Board that sufficient operating, accounting, and financial controls are in existence and are adequately reviewed by programs of internal and external audits.

The Audit Committee discussed with Entergy's internal auditors and the independent public accountants (Coopers & Lybrand L.L.P.) the overall scope and specific plans for their respective audits, as well as System Energy's financial statements and the adequacy of System Energy's internal controls. The committee met, together and separately, with Entergy's internal auditors and independent public accountants, without management present, to discuss the results of their audits, their evaluation of System Energy's internal controls, and the overall quality of System Energy's financial reporting. The meetings also were designed to facilitate and encourage any private communication between the committee and the internal auditors or independent public accountants.

H. DUKE SHACKELFORD
Chairman, Audit Committee

REPORT OF INDEPENDENT ACCOUNTANTS

To the Board of Directors and Shareholder of
System Energy Resources, Inc.

We have audited the accompanying balance sheet of System Energy Resources, Inc. as of December 31, 1994, and the related statements of income, retained earnings and cash flows for the year then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audit. The financial statements of the Company as of December 31, 1993 and for the years ended December 31, 1993 and 1992, were audited by other auditors, whose report, dated February 11, 1994, included explanatory paragraphs that described a change in a method of accounting for income taxes discussed in Note 3 to these financial statements and an uncertainty relating to a regulatory proceeding which is discussed in Note 2 to these financial statements.

We conducted our audit in accordance with generally accepted auditing standards. Those standards require that we plan and perform the audit to obtain reasonable assurance 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 audit provides a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 1994, and the result of its operations and its cash flows for the year then ended in conformity with generally accepted accounting principles.

COOPERS & LYBRAND L.L.P.
New Orleans, Louisiana
February 21, 1995

INDEPENDENT AUDITORS' REPORT

To the Shareholder and Board of Directors of
System Energy Resources, Inc.

We have audited the accompanying balance sheet of System Energy Resources, Inc. (System Energy) as of December 31, 1993, and the related statements of income, retained earnings, and cash flows for each of the two years in the period ended December 31, 1993. These financial statements are the responsibility of System Energy's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with generally accepted auditing standards. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such financial statements present fairly, in all material respects, the financial position of System Energy at December 31, 1993, and the results of its operations and its cash flows for each of the two years in the period ended December 31, 1993 in conformity with generally accepted accounting principles.

As discussed in Notes 3 to the financial statements, in 1993 System Energy changed its methods of accounting for income taxes.

DELOITTE & TOUCHE LLP
New Orleans, Louisiana
February 11, 1994 (November 30, 1994 as to Note 2, "Rate and Regulatory Matters - FERC Settlement")

SYSTEM ENERGY RESOURCES, INC.
BALANCE SHEETS
ASSETS

	December 31,	
	1994	1993
	(In Thousands)	
Utility Plant:		
Electric	$2,939,384	$3,027,537
Electric plant under lease	439,378	437,941
Construction work in progress	46,547	41,442
Nuclear fuel under capital lease	46,688	79,625
Nuclear fuel	26,360	-
Total	3,498,357	3,586,545
Less - accumulated depreciation	751,717	669,666
Utility plant - net	2,746,640	2,916,879
Other Investments:		
Decommissioning trust fund	30,359	24,787
Current Assets:		
Cash and cash equivalents:		
Cash	-	2,424
Temporary cash investments - at cost, which approximates market:		
Associated companies	5,489	46,601
Other	84,214	147,107
Total cash and cash equivalents	89,703	196,132
Accounts receivable:		
Associated companies	7,450	57,216
Other	3,412	2,057
Materials and supplies - at average cost	71,991	69,765
Recoverable income taxes	-	63,400
Prepayments and other	5,429	4,835
Total	177,985	393,405
Deferred Debits and Other Assets:		
Regulatory Assets:		
SFAS 109 regulatory asset - net	389,264	384,317
Unamortized loss on reacquired debt	54,577	17,258
Other regulatory assets	199,080	108,518
Recoverable income taxes	-	29,289
Other	15,454	16,613
Total	658,375	555,995
TOTAL	$3,613,359	$3,891,066

See Notes to Financial Statements.

SYSTEM ENERGY RESOURCES, INC.
BALANCE SHEETS
CAPITALIZATION AND LIABILITIES

	December 31,	
	1994	1993
	(In Thousands)	
Capitalization:		
Common stock, no par value, authorized 1,000,000 shares; issued and outstanding 789,350 shares in 1994 and 1993	$789,350	$789,350
Paid-in capital	7	7
Retained earnings	85,681	228,574
Total common shareholder's equity	875,038	1,017,931
Long-term debt	1,438,305	1,511,914
Total	2,313,343	2,529,845
Other Noncurrent Liabilities:		
Obligations under capital leases	18,688	24,679
Other	14,342	18,229
Total	33,030	42,908
Current Liabilities:		
Currently maturing long-term debt	105,000	230,000
Accounts payable:		
Associated companies	32,272	1,928
Other	23,204	18,223
Taxes accrued	35,392	20,952
Interest accrued	40,796	48,929
Obligations under capital leases	28,000	55,000
Other	19,794	2,805
Total	284,448	377,837
Deferred Credits:		
Accumulated deferred income taxes	746,502	775,630
Accumulated deferred investment tax credits	110,584	113,849
FERC Settlement - refund obligation	60,388	-
Other	65,064	50,997
Total	982,538	940,476
Commitments and Contingencies (Notes 2, 7, and 8)		
TOTAL	$3,613,359	$3,891,066

See Notes to Financial Statements.

SYSTEM ENERGY RESOURCES, INC.
STATEMENTS OF CASH FLOWS

	For the Years Ended December 31,		
	1994	1993	1992
		(In Thousands)	
Operating Activities:			
Net income	$5,407	$93,927	$130,141
Noncash items included in net income:			
Depreciation and decommissioning	93,861	90,920	85,932
Deferred income taxes and investment tax credits	(30,640)	15,832	70,356
Allowance for equity funds used during construction	(1,090)	(772)	(681)
Amortization of debt discount	4,388	4,520	6,417
Amortization of loss on reacquired debt	2,343	-	-
Changes in working capital:			
Receivables	48,411	6,199	225
Accounts payable	35,469	(15,123)	(30,517)
Taxes accrued	14,430	(2,272)	2,672
Interest accrued	(8,133)	(1,631)	1,252
Other working capital accounts	14,024	2,832	(4,412)
Recoverable income taxes	92,689	130,152	(3,475)
Decommissioning trust contributions	(5,157)	(4,911)	(5,641)
FERC Settlement - refund obligation	60,388	-	-
Other	10,597	(1,617)	86
Net cash flow provided by operating activities	336,987	318,056	252,355
Investing Activities:			
Construction expenditures	(20,766)	(23,083)	(21,671)
Allowance for equity funds used during construction	1,090	772	681
Nuclear fuel purchases	(26,414)	(32,822)	(13,724)
Proceeds from sale/leaseback of nuclear fuel	-	32,822	28,094
Net cash flow used in investing activities	(46,090)	(22,311)	(6,620)
Financing Activities:			
Proceeds from the issuance of first mortgage bonds	59,410	60,000	220,000
Retirement of first mortgage bonds	(260,000)	(108,308)	(240,750)
Premium and expenses paid on refinancing sale/leaseback bonds	(48,436)	-	-
Common stock dividends paid	(148,300)	(233,100)	(137,700)
Net cash flow used in financing activities	(397,326)	(281,408)	(158,450)
Net increase (decrease) in cash and cash equivalents	(106,429)	14,337	87,285
Cash and cash equivalents at beginning of period	196,132	181,795	94,510
Cash and cash equivalents at end of period	$89,703	$196,132	$181,795
SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION:			
Cash paid (received) during the period for:			
Interest - net of amount capitalized	$176,503	$186,786	$201,287
Income taxes (refund)	($39,586)	($65,992)	$21,431
Noncash investing and financing activities:			
Capital lease obligations incurred	-	$45,089	$28,094
Deficiency of fair value of decommissioning trust assets under amount invested	($1,515)	-	-

See Notes to Financial Statements.

SYSTEM ENERGY RESOURCES, INC.

MANAGEMENT'S FINANCIAL DISCUSSION AND ANALYSIS

LIQUIDITY AND CAPITAL RESOURCES

The financial condition of System Energy significantly depends on the continued commercial operation of Grand Gulf 1 and on the receipt of payments from AP&L, LP&L, MP&L, and NOPSI. Payments under the Unit Power Sales Agreement are System Energy's only source of operating revenues. Net cash flow from operations totaled $337 million, $318 million, and $252 million in 1994, 1993, and 1992, respectively. In recent years, this cash flow has been sufficient to meet substantially all investing and financing requirements, including capital expenditures, dividends, and debt maturities. See Note 7 for information on System Energy's capital and refinancing requirements in 1995 - 1997. Also, to the extent current market interest and dividend rates allow, System Energy may continue to refinance high-cost debt prior to maturity.

As discussed in Note 2, in November 1994, FERC approved an agreement settling a long-standing dispute involving income tax allocation procedures of System Energy. In connection with this settlement, System Energy refunded approximately $61.7 million to AP&L, LP&L, MP&L, and NOPSI, which in turn have made or will make refunds or credits to their customers (except for those portions attributable to AP&L's and LP&L's retained share of Grand Gulf 1 costs). Additionally, System Energy will refund a total of approximately $62 million, plus interest, to AP&L, LP&L, MP&L, and NOPSI over the period through June 2004. AP&L, LP&L, MP&L, and NOPSI also wrote-off certain related unamortized balances of deferred investment tax credits. See Note 2 for further information on the FERC Settlement.

As a result of the charges associated with the FERC Settlement, System Energy obtained the consent of certain banks (parties to the Reimbursement Agreement) to waive temporarily the fixed charge coverage covenant in the letters of credit and Reimbursement Agreement related to the Grand Gulf 1 sale and leaseback transaction, until November 30, 1995. System Energy expects that upon expiration of the waiver period, it will be in compliance with the fixed charge coverage covenant. Absent a waiver, System Energy's failure to perform this covenant could cause a draw under the letters of credit and/or early termination of the letters of credit. If the letters of credit were not replaced in a timely manner, a default or early termination of System Energy's leases could result.

Earnings coverage tests, bondable property additions, and equity ratio requirements contained in its mortgage, and in its letters of credit and Reimbursement Agreement in connection with the Grand Gulf 1 sale and leaseback transactions, limit the amount of first mortgage bonds that System Energy can issue. Based on the most restrictive applicable tests as of December 31, 1994, and assuming an annual interest rate of 9.25%, System Energy could have issued $241 million of additional first mortgage bonds. System Energy has the conditional ability to issue first mortgage bonds against the retirement of first mortgage bonds, in some cases, without satisfying an earnings coverage test.

In connection with the financing of Grand Gulf 1, Entergy Corporation has undertaken, in the Capital Funds Agreement, to provide to System Energy sufficient capital to (1) maintain System Energy's equity capital at an amount equal to at least 35% of System Energy's total capitalization (excluding short-term debt), (2) permit the continuation of commercial operation of Grand Gulf 1, and (3) enable System Energy to pay in full all borrowings, whether at maturity, on prepayment, on acceleration, or otherwise. In addition, Entergy Corporation has agreed in the Capital Funds Agreement to make certain cash capital contributions, if required, to enable System Energy to make payments when due on specific issues of its long-term debt.

See Note 4 for information regarding System Energy's short-term borrowings.

SYSTEM ENERGY RESOURCES, INC.
STATEMENTS OF INCOME

	For the Years Ended December 31,		
	1994	1993	1992
		(In Thousands)	
Operating Revenues	$474,963	$650,768	$723,410
Operating Expenses:			
Operation and maintenance:			
Fuel and fuel-related expenses	48,107	42,296	55,110
Other operation and maintenance	96,504	135,349	132,341
Depreciation and decommissioning	93,861	90,920	90,628
Taxes other than income taxes	26,637	26,589	28,717
Income taxes	38,087	83,412	93,438
Total	303,196	378,566	400,234
Operating Income	171,767	272,202	323,176
Other Income (Deductions):			
Allowance for equity funds used during construction	1,090	772	681
Miscellaneous - net	6,402	6,518	5,816
Income taxes	1,250	4,859	4,584
Total	8,742	12,149	11,081
Interest Charges:			
Interest on long-term debt	169,248	189,338	203,035
Other interest - net	7,257	1,600	1,506
Allowance for borrowed funds used during construction	(1,403)	(514)	(425)
Total	175,102	190,424	204,116
Net Income	$5,407	$93,927	$130,141

See Notes to Financial Statements.

SYSTEM ENERGY RESOURCES, INC.
STATEMENTS OF RETAINED EARNINGS

	For the Years Ended December 31,		
	1994	1993	1992
		(In Thousands)	
Retained Earnings, January 1	$228,574	$367,747	$375,306
Add:			
Net income	5,407	93,927	130,141
Total	233,981	461,674	505,447
Deduct:			
Dividends declared	148,300	233,100	137,700
Retained Earnings, December 31 (Note 6)	$85,681	$228,574	$367,747

See Notes to Financial Statements.

SYSTEM ENERGY RESOURCES, INC.

MANAGEMENT'S FINANCIAL DISCUSSION AND ANALYSIS

RESULTS OF OPERATIONS

Net Income

Net income decreased in 1994 primarily due to the effect of the FERC Settlement which reduced income by $80.2 million (see Note 2) and a lower rate of return on System Energy's decreasing investment in Grand Gulf 1, partially offset by a decrease in interest expense. Net income decreased in 1993 primarily due to the impact of the FERC Return on Equity Case settlement regarding the return on equity component of System Energy's formula wholesale rates, as discussed in Note 2. This decrease in revenue was partially offset by a reduction in interest expense due to the retirement of high-cost debt.

Significant factors affecting the results of operations and causing variances between the years 1994 and 1993, and 1993 and 1992 are discussed under "Revenues" and "Expenses" below.

Revenues

Operating revenues recover operating expenses, depreciation, and capital costs attributable to Grand Gulf 1. The capital costs are computed by allowing a return, currently set at a rate of 11.0%, (see Note 2 for further information on the FERC Return on Equity Case) on System Energy's common equity funds allocable to its net investment in Grand Gulf 1 plus System Energy's effective interest cost for its debt allocable to its investment in Grand Gulf 1.

Operating revenues decreased in 1994 due primarily to the effect of the FERC Settlement as discussed in "Net Income" above, a lower return on System Energy's decreasing investment in Grand Gulf 1 (caused by depreciation of the unit) and decreased operation and maintenance expenses. Future revenues attributable to the return on investment are expected to decline each year as a result of the depreciation of System Energy's investment in Grand Gulf 1. Operating revenues decreased in 1993 due primarily to the effect of the FERC Return on Equity Case settlement which reduced System Energy's return on equity as discussed in "Net Income" above and a lower return on System Energy's decreasing investment in Grand Gulf 1.

Expenses

Operating expenses decreased in 1994 due primarily to lower other operation and maintenance expense and lower income tax expense. Operating expenses decreased in 1993 due primarily to lower fuel and lower income tax expense.

Grand Gulf 1 was on-line for 345 of 365 days in 1994 as compared with 284 of 365 days in 1993. The unit capability factor, which is a measure of the unit's performance (based on a ratio of available energy generation to the maximum power capability multiplied by the period hours), was 92.26% for 1994 as compared with 76.1% for 1993. These variances are primarily due to the unit's sixth refueling outage that lasted from September 28, 1993 to December 3, 1993, (67 days) and to a lesser extent, the unplanned outages in 1994 totaling 20 days, compared to 1993 of 14 days. The lower level of outages for 1994 increased fuel for electric generation, partially offset by less expensive nuclear fuel and increased operating efficiency. Nonfuel operation and maintenance expense decreased significantly in 1994 also due to the lower level of outages. The 1993 decrease in fuel for electric generation and fuel related expenses is primarily due to the sixth refueling outage and

to refueling with less expensive nuclear fuel. Increased operating efficiency was another contributor to the 1993 decrease. Nonfuel operation and maintenance expense increased in 1993 due primarily to the sixth refueling outage as discussed above.

Total income taxes decreased in 1994 due primarily to lower pretax book income. Total income taxes decreased in 1993 due primarily to lower pretax book income partially offset by an increase in the federal income tax rate as a result of OBRA.

Interest expense decreased in 1994 due primarily to the refinancing and maturity of high-cost long-term debt partially offset by interest associated with the FERC Settlement refunds (see Note 2).

FERC Settlement

See Note 2 for information with respect to a settlement between System Energy and FERC in which System Energy refunded approximately $61.7 million to AP&L, LP&L, MP&L, and NOPSI, which in turn have made or will make refunds or credits to their customers (except for those portions attributable to AP&L's and LP&L's retained share of Grand Gulf costs). Additionally, System Energy will refund a total of approximately $62 million, plus interest, to AP&L, LP&L, MP&L, and NOPSI over the period through June 2004. AP&L, LP&L, MP&L, and NOPSI also wrote-off certain related unamortized balances of deferred investment tax credits.

Accounting Issues

Proposed Accounting Standard - The FASB has proposed a SFAS on "Accounting for the Impairment of Long-Lived Assets," effective January 1, 1996. The proposed standard describes circumstances which may result in assets being impaired and provides criteria for recognition and measurement of asset impairment. Certain operations of System Energy are potentially affected by this standard, and any resulting write-offs will depend on future operating costs, efficiency and availability of Grand Gulf 1, and the future market for energy over the remaining life of the unit. Based on current estimates, System Energy anticipates that future revenues will fully recover the costs of such operations.

Continued Application of SFAS 71 - System Energy's financial statements currently reflect assets and costs based on current cost-based ratemaking regulations, in accordance with SFAS 71, "Accounting for the Effects of Certain Types of Regulation." The electric utility industry is changing and these changes could possibly result in the discontinuance of the application of SFAS 71 which would result in the elimination of regulatory assets and liabilities. See Note 1 for further information.

Accounting for Decommissioning Costs - The FASB is currently reviewing the accounting for decommissioning of nuclear plants. This project could possibly change System Energy's, as well as the entire utility industry's, accounting for such costs. For further information, see Note 7.

NOTE 1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

System Energy maintains accounts in accordance with FERC guidelines. Certain previously reported amounts have been reclassified to conform to current classifications.

Organization

System Energy is a generating company providing electricity to AP&L, LP&L, MP&L, and NOPSI and has a 90% interest in Grand Gulf 1, a nuclear generating station with a total capability of 1,143 MW that began operation in 1985. In June 1990, Entergy Operations assumed responsibility for the operation and maintenance of Grand Gulf 1.

System Energy has a combined ownership and leasehold interest of 90% and SMEPA has an undivided ownership interest of 10% in Grand Gulf 1. System Energy records its investment associated with Grand Gulf 1 to the extent to which it owns and maintains a leasehold interest in the generating station. Likewise, System Energy's operating expenses reflected in the accompanying financial statements represent 90% of such Grand Gulf 1 expenses.

Utility Plant

Utility plant is stated at original cost. The original cost of utility plant retired or removed, plus the applicable removal costs, less salvage, is charged to accumulated depreciation. Maintenance, repairs, and minor replacement costs are charged to operating expenses. Substantially all of the utility plant owned by System Energy is subject to the lien of its first mortgage bond indenture.

Utility plant includes the portions of Grand Gulf 1 that were sold and are currently under lease. System Energy retired this property from its continuing property records as formerly owned property released from and no longer subject to System Energy's mortgage and deed of trust. System Energy is reflecting such leased property for financial reporting purposes as property under lease from others and is depreciating this property over the life of the basic lease term. Such depreciation is being deferred as a regulatory asset until recoverable from customers in future periods (see Note 8).

Depreciation is computed on a straight-line basis at rates based on the estimated service lives and costs of removal of the various classes of property. Depreciation provisions on average depreciable property approximated 3.0% in 1994 and 2.9% in 1993 and 1992.

AFUDC represents the approximate net composite interest cost of borrowed funds and a reasonable return on the equity funds used for construction. Although AFUDC increases utility plant and increases earnings, it is only realized in cash through depreciation provisions included in rates. System Energy's effective composite rates for AFUDC were 10.7%, 11.6%, and 12.3% for 1994, 1993, and 1992, respectively.

Income Taxes

System Energy, its parent, and affiliates file a consolidated federal income tax return. Income taxes are allocated to System Energy in proportion to its contribution to consolidated taxable income. SEC regulations require that no Entergy Corporation subsidiary pay more taxes than it would have had a separate income tax return been filed. Deferred taxes are recorded for all temporary differences between book and taxable income. Investment tax credits are deferred and amortized based upon the average useful life of the related property in accordance with rate treatment. As discussed in Note 3, in 1993 System Energy changed its accounting for income taxes to conform with SFAS 109.

In addition, System Energy files a consolidated Mississippi state income tax return with certain other System companies.

Reacquired Debt

The premiums and costs associated with reacquired debt are being amortized over the life of the related new issuances, in accordance with ratemaking treatment.

Cash and Cash Equivalents

System Energy considers all unrestricted highly liquid debt instruments purchased with an original maturity of three months or less to be cash equivalents.

Continued Application of SFAS 71

As a result of the EPAct and actions of regulatory commissions, the electric utility industry is moving toward a combination of competition and a modified regulatory environment. System Energy's financial statements currently reflect assets and costs based on current cost-based ratemaking regulations, in accordance with SFAS 71, "Accounting for the Effects of Certain Types of Regulation." Continued applicability of SFAS 71 to System Energy's financial statements requires that rates set by an independent regulator on a cost of service basis (including a reasonable rate of return on invested capital) can actually be charged to and collected from customers.

In the event that either all or a portion of a utility's operations cease to meet those criteria for various reasons, including deregulation, a change in the method of regulation, or a change in the competitive environment for the utility's regulated services, the utility should discontinue application of SFAS 71 for the relevant portion. That discontinuation should be reported by elimination from the balance sheet of the effects of any actions of regulators recorded as regulatory assets and liabilities.

As of December 31, 1994, and for the foreseeable future, System Energy's financial statements continue to follow SFAS 71.

Fair Value Disclosure

The estimated fair value of financial instruments has been determined by System Energy, using available market information and appropriate valuation methodologies. However, considerable judgment is required in developing the estimates of fair value. Therefore, estimates are not necessarily indicative of the amounts that

NOTE 1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

System Energy maintains accounts in accordance with FERC guidelines. Certain previously reported amounts have been reclassified to conform to current classifications.

Organization

System Energy is a generating company providing electricity to AP&L, LP&L, MP&L, and NOPSI and has a 90% interest in Grand Gulf 1, a nuclear generating station with a total capability of 1,143 MW that began operation in 1985. In June 1990, Entergy Operations assumed responsibility for the operation and maintenance of Grand Gulf 1.

System Energy has a combined ownership and leasehold interest of 90% and SMEPA has an undivided ownership interest of 10% in Grand Gulf 1. System Energy records its investment associated with Grand Gulf 1 to the extent to which it owns and maintains a leasehold interest in the generating station. Likewise, System Energy's operating expenses reflected in the accompanying financial statements represent 90% of such Grand Gulf 1 expenses.

Utility Plant

Utility plant is stated at original cost. The original cost of utility plant retired or removed, plus the applicable removal costs, less salvage, is charged to accumulated depreciation. Maintenance, repairs, and minor replacement costs are charged to operating expenses. Substantially all of the utility plant owned by System Energy is subject to the lien of its first mortgage bond indenture.

Utility plant includes the portions of Grand Gulf 1 that were sold and are currently under lease. System Energy retired this property from its continuing property records as formerly owned property released from and no longer subject to System Energy's mortgage and deed of trust. System Energy is reflecting such leased property for financial reporting purposes as property under lease from others and is depreciating this property over the life of the basic lease term. Such depreciation is being deferred as a regulatory asset until recoverable from customers in future periods (see Note 8).

Depreciation is computed on a straight-line basis at rates based on the estimated service lives and costs of removal of the various classes of property. Depreciation provisions on average depreciable property approximated 3.0% in 1994 and 2.9% in 1993 and 1992.

AFUDC represents the approximate net composite interest cost of borrowed funds and a reasonable return on the equity funds used for construction. Although AFUDC increases utility plant and increases earnings, it is only realized in cash through depreciation provisions included in rates. System Energy's effective composite rates for AFUDC were 10.7%, 11.6%, and 12.3% for 1994, 1993, and 1992, respectively.

Income Taxes

System Energy, its parent, and affiliates file a consolidated federal income tax return. Income taxes are allocated to System Energy in proportion to its contribution to consolidated taxable income. SEC regulations require that no Entergy Corporation subsidiary pay more taxes than it would have had a separate income tax return been filed. Deferred taxes are recorded for all temporary differences between book and taxable income. Investment tax credits are deferred and amortized based upon the average useful life of the related property in accordance with rate treatment. As discussed in Note 3, in 1993 System Energy changed its accounting for income taxes to conform with SFAS 109.

In addition, System Energy files a consolidated Mississippi state income tax return with certain other System companies.

Reacquired Debt

The premiums and costs associated with reacquired debt are being amortized over the life of the related new issuances, in accordance with ratemaking treatment.

Cash and Cash Equivalents

System Energy considers all unrestricted highly liquid debt instruments purchased with an original maturity of three months or less to be cash equivalents.

Continued Application of SFAS 71

As a result of the EPAct and actions of regulatory commissions, the electric utility industry is moving toward a combination of competition and a modified regulatory environment. System Energy's financial statements currently reflect assets and costs based on current cost-based ratemaking regulations, in accordance with SFAS 71, "Accounting for the Effects of Certain Types of Regulation." Continued applicability of SFAS 71 to System Energy's financial statements requires that rates set by an independent regulator on a cost of service basis (including a reasonable rate of return on invested capital) can actually be charged to and collected from customers.

In the event that either all or a portion of a utility's operations cease to meet those criteria for various reasons, including deregulation, a change in the method of regulation, or a change in the competitive environment for the utility's regulated services, the utility should discontinue application of SFAS 71 for the relevant portion. That discontinuation should be reported by elimination from the balance sheet of the effects of any actions of regulators recorded as regulatory assets and liabilities.

As of December 31, 1994, and for the foreseeable future, System Energy's financial statements continue to follow SFAS 71.

Fair Value Disclosure

The estimated fair value of financial instruments has been determined by System Energy, using available market information and appropriate valuation methodologies. However, considerable judgment is required in developing the estimates of fair value. Therefore, estimates are not necessarily indicative of the amounts that

System Energy could realize in a current market exchange. In addition, gains or losses realized on financial instruments may be reflected in future rates and not accrue to the benefit of stockholders.

System Energy considers the carrying amounts of financial instruments classified as current assets and liabilities to be a reasonable estimate of their fair value because of the short maturity of these instruments. In addition, System Energy does not presently expect that performance of its obligations will be required in connection with certain off-balance sheet commitments and guarantees considered financial instruments. Due to this factor, and because of the related party nature of these commitments and guarantees, determination of fair value is not considered practicable. See Notes 5 and 7 for additional fair value disclosure.

System Energy adopted the provisions of SFAS 115, "Accounting for Certain Investments in Debt and Equity Securities," effective January 1, 1994. As a result, at December 31, 1994, System Energy has recorded on the balance sheet a reduction of $1.5 million in decommissioning trust funds, representing the amount by which the fair value of the securities held in such funds is less than amounts recovered in rates for decommissioning and deposited in the funds and the related earnings on the amounts deposited. Due to the regulatory treatment for decommissioning trust funds, System Energy recorded an offsetting amount in unrealized losses on investment securities as a regulatory asset.

NOTE 2. RATE AND REGULATORY MATTERS

FERC Settlement

In November 1994, FERC approved an agreement settling a long-standing dispute involving income tax allocation procedures of System Energy. In accordance with the agreement, System Energy refunded approximately $61.7 million to AP&L, LP&L, MP&L, and NOPSI, which in turn have made or will make refunds or credits to their customers (except for those portions attributable to AP&L's and LP&L's retained share of Grand Gulf 1 costs). Additionally, System Energy will refund a total of approximately $62 million, plus interest, to AP&L, LP&L, MP&L, and NOPSI over the period through June 2004. The settlement also required the write-off of certain related unamortized balances of deferred investment tax credits by AP&L, LP&L, MP&L, and NOPSI. The settlement reduced Entergy Corporation's consolidated net income for the year ended December 31, 1994, by approximately $68.2 million, offset by the write-off of the unamortized balances of related deferred investment tax credits of approximately $69.4 million ($2.9 million for Entergy Corporation, $27.3 million for AP&L; $31.5 million for LP&L; $6 million for MP&L; and $1.7 million for NOPSI). System Energy also reclassified from utility plant to other deferred debits approximately $81 million of other Grand Gulf 1 costs. Although excluded from rate base, System Energy will be permitted to recover such costs over a 10-year period. Interest on the $62 million refund and the loss of the return on the $81 million of other Grand Gulf 1 costs will reduce Entergy's and System Energy's net income by approximately $10 million annually over the next 10 years.

As a result of the charges associated with the settlement, System Energy obtained the consent of certain banks (parties to the Reimbursement Agreement) to waive temporarily the fixed charge coverage covenant in the letters of credit and Reimbursement Agreement related to the Grand Gulf 1 sale and leaseback transaction until November 30, 1995. System Energy expects that upon expiration of the waiver period, it will be in compliance with the fixed charge coverage covenant. Absent a waiver, System Energy's failure to perform this covenant could cause a draw under the letters of credit and/or early termination of the letters of credit. If the letters of credit were not replaced in a timely manner, a default or early termination of System Energy's leases could result.

FERC Return on Equity Case

In August 1992, FERC instituted an investigation of the return on equity (ROE) component of all formula wholesale rates for System Energy as well as AP&L, LP&L, MP&L, and NOPSI. Payments received by System Energy under the Unit Power Sales Agreement are its only source of operating revenue. Rates under the Unit Power Sales Agreement are based on System Energy's cost of service including a return on common equity which had been set at 13% (see below).

In August 1993, Entergy and the state regulatory agencies that intervened in the proceeding reached an agreement (Settlement Agreement) in this matter. The Settlement Agreement, which was approved by FERC on October 25, 1993, provides that an 11.0% ROE will be included in the formula rates under the Unit Power Sales Agreement. The Unit Power Sales Agreement formula rate, including the 11.0% ROE component, will remain in effect without change for two years, until early August 1995. System Energy's refunds payable to AP&L, LP&L, MP&L, and NOPSI, which were due prospectively from November 3, 1992, were reflected as a credit to their bills in October 1993. These refunds decreased System Energy's 1993 revenues and net income by approximately $29.4 million and $18.2 million, respectively.

NOTE 3. INCOME TAXES

Income tax expense consisted of the following:

	For the Years Ended December 31,		
	1994	1993	1992
		(In Thousands)	
Current:			
Federal	$54,295	$ 59,050	$ 13,890
State	13,182	3,671	6,786
Total	67,477	62,721	20,676
Deferred - net:			
Liberalized depreciation	24,910	46,600	43,873
Nuclear fuel	790	2,706	(3,299)
Capitalized interest	(1,024)	(456)	(1,402)
Taxes capitalized	(929)	(929)	(935)
Decontamination and decommissioning fund	1,117	5,601	-
Bond reacquisition	626	(787)	852
Accrued FERC Settlement	(23,098)	-	-
Alternative minimum tax	(17,727)	(1,579)	-
Adjustment to GG2 tax basis	(14,037)	-	-
Adjustment of prior year taxes	2,747	(3,249)	1,157
Other	(750)	(1,623)	(2,191)
Total	(27,375)	46,284	38,055
Investment tax credit adjustments - net	(3,265)	(30,452)	30,123
Recorded income tax expense	$36,837	$ 78,553	$ 88,854
Charged to operations	$38,087	$ 83,412	$ 93,438
Credited to other income	(1,250)	(4,859)	(4,584)
Recorded income tax expense	36,837	78,553	88,854
Income taxes applied against the debt component of AFUDC	-	-	253
Total income taxes	$36,837	$ 78,553	$ 89,107

Total income taxes differ from the amounts computed by applying the statutory federal income tax rate to income or loss before taxes. The reasons for the differences were:

	For the Years Ended December 31,					
	1994		1993		1992	
	Amount	% of Pretax Income	Amount	% of Pretax Income	Amount	% of Pretax Income
	(Dollars in Thousands)					
Computed at statutory rate	$14,785	35.0	$60,368	35.0	$74,458	34.0
Increases (reductions) in tax resulting from:						
Depreciation	14,541	34.4	12,839	7.4	11,520	5.3
State income taxes net of federal income tax effect	7,565	17.9	6,778	3.9	8,380	3.8
Amortization of investment tax credits	(3,476)	(8.2)	(3,759)	(2.2)	(3,865)	(1.8)
Adjustment of Prior Year Taxes	2,947	7.0	5,292	3.0	-	-
Other - (net)	475	1.1	(2,965)	(1.6)	(1,639)	(0.7)
Recorded income tax expense	36,837	87.2	78,553	45.5	88,854	40.6
Income taxes applied against the debt component of AFUDC	-	-	-	-	253	0.1
Total income taxes	$36,837	87.2	$78,553	45.5	$89,107	40.7

Significant components of System Energy's net deferred tax liabilities, as of December 31, 1994 and 1993, were:

	1994	1993
	(In Thousands)	
Deferred tax liabilities:		
Net regulatory assets	$(428,492)	$ (425,318)
Plant related basis differences	(577,286)	(552,782)
Other	(14,350)	(16,343)
Total	$ (1,020,128)	$ (994,443)
Deferred tax assets:		
Sale and leaseback	$ 145,731	$ 142,850
FERC Settlement	23,098	-
Accumulated deferred investment tax credit	42,298	43,547
Alternative minimum tax credit	38,179	20,452
Recoverable income tax	-	92,689
Adjustment to GG2 tax basis	14,037	-
Other	10,283	11,964
Total	$ 273,626	$ 311,502
Net deferred tax liabilities	$ (746,502)	$ (682,941)

The alternative minimum tax (AMT) credit at December 31, 1994 was $38.2 million. This AMT credit can be carried forward indefinitely and will reduce System Energy's federal income tax liability in the future.

In 1993, System Energy adopted SFAS 109. SFAS 109 required that deferred income taxes be recorded for all temporary differences and carryforwards, and that deferred tax balances be based on enacted tax laws at tax rates that are expected to be in effect when the temporary differences reverse. SFAS 109 requires that regulated enterprises recognize adjustments resulting from implementation as regulatory assets or liabilities if it is probable that such amounts will be recovered from or returned to customers in future rates. A substantial majority of the adjustments required by SFAS 109 was recorded to deferred tax balance sheet accounts with offsetting adjustments to regulatory assets and liabilities. As a result of the adoption of SFAS 109, 1993 net income was reduced by $0.4 million, assets were increased by $327.9 million, and liabilities were increased by $327.5 million. The cumulative effect of the adoption of SFAS 109 is included in income tax expense charged to operations.

In connection with an Internal Revenue Service (IRS) audit of Entergy's 1988, 1989, and 1990 consolidated federal income tax returns, the IRS proposed that adjustments be made to the Grand Gulf 2 abandonment loss deduction claimed on Entergy's 1989 consolidated federal income tax return. The final agreement with the IRS required Entergy Corporation to pay $4.3 million in connection with the abandonment loss issue.

In August 1994, Entergy received an IRS report covering the federal income tax audit of Entergy Corporation and subsidiaries for the years 1988 - 1990. The report asserts an $80 million tax deficiency for the 1990 consolidated federal income tax returns related primarily to the application of accelerated investment tax credits associated with Waterford 3 and Grand Gulf nuclear plants. Entergy believes there is no material tax deficiency and is vigorously contesting the proposed assessment.

NOTE 4. LINES OF CREDIT AND RELATED BORROWINGS

The SEC has authorized System Energy to effect short-term borrowings up to $125 million, which may be increased to as much as $195 million after further SEC approval. This authorization is effective through November 30, 1996. In addition, System Energy can borrow from the Money Pool, subject to its maximum authorized level of short-term borrowings and the availability of funds. System Energy had no outstanding borrowings under the Money Pool arrangement or under bank lines of credit as of December 31, 1994.

NOTE 5. LONG-TERM DEBT

The long-term debt of System Energy as of December 31, 1994 and 1993, was as follows:

Maturities		Interest Rates			
From	To	From	To	1994	1993
				(In Thousands)	
First Mortgage Bonds					
1995	1999	6.0%	10-1/2%	$ 475,000	$ 615,000
2002		8-1/4%		70,000	130,000
2016		11-3/8%		90,319	90,319
Governmental Obligations*					
2013	2016	8-1/4%	12-1/2%	416,600	416,600
Grand Gulf Lease Obligation, 7.02% (Note 8)				500,000	500,000
Unamortized Discount				(8,614)	(10,005)
Total Long-Term Debt				1,543,305	1,741,914
Less Amount Due Within One Year				105,000	230,000
Long-Term Debt Excluding Amount Due Within One Year				$1,438,305	$1,511,914

* Consists of pollution control bonds, certain series of which are secured by non-interest bearing first mortgage bonds.

The fair value of System Energy's long-term debt, excluding Grand Gulf lease obligation, as of December 31, 1994 and 1993, was estimated to be $1,091 million and $1,397.8 million, respectively. Fair values were determined using bid prices reported by dealer markets and by nationally recognized investment banking firms. For the years 1995, 1996, 1997, 1998, and 1999 System Energy has long-term debt maturities and sinking fund requirements (in millions) of $105, $250, $10, $70, and $70, respectively.

NOTE 6. DIVIDEND RESTRICTIONS

Various agreements relating to the long-term debt of System Energy restrict the payment of cash dividends or other distributions on its common stock. As of December 31, 1994, $41.7 million of System Energy's retained earnings were restricted against the payment of cash dividends or other distributions on common stock.

NOTE 7. COMMITMENTS AND CONTINGENCIES

Capital Requirements and Financing

Construction expenditures (excluding nuclear fuel) for the years 1995, 1996, and 1997 are estimated to total $22 million, $21.6 million, and $19.1 million, respectively. System Energy will also require $365 million during the period 1995-1997 to meet long-term debt maturities. System Energy plans to meet the above requirements with internally generated funds and cash on hand, supplemented by the issuance of long-term debt. See Note 5 for the possible issuance of new first mortgage bonds and the potential refunding, redemption, purchase, or other acquisition of certain series of outstanding first mortgage bonds.

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Construction expenditures (excluding nuclear fuel) for the years 1995, 1996, and 1997 are estimated to total $22 million, $21.6 million, and $19.1 million, respectively. System Energy will also require $365 million during the period 1995-1997 to meet long-term debt maturities. System Energy plans to meet the above requirements with internally generated funds and cash on hand, supplemented by the issuance of long-term debt. See Note 5 for the possible issuance of new first mortgage bonds and the potential refunding, redemption, purchase, or other acquisition of certain series of outstanding first mortgage bonds.

Capital Funds Agreement

Entergy Corporation has agreed to supply to System Energy sufficient capital to (1) maintain System Energy's equity capital at an amount equal to a minimum of 35% of its total capitalization (excluding short-term debt), and (2) permit the continuation of commercial operation of Grand Gulf 1 and to pay in full all indebtedness for borrowed money of System Energy when due under any circumstances. In addition, under supplements to the Capital Funds Agreement assigning System Energy's rights as security for specific debt of System Energy, Entergy Corporation has agreed to make cash capital contributions to enable System Energy to make payments on such debt when due.

System Energy has entered into various agreements with AP&L, LP&L, MP&L, and NOPSI, whereby AP&L, LP&L, MP&L, and NOPSI are obligated to purchase their respective entitlements of capacity (discussed below) and energy from System Energy's 90% ownership and leasehold interest in Grand Gulf 1, and to make payments that, together with other available funds, are adequate to cover System Energy's operating expenses. System Energy would have to secure funds from other sources, including Entergy's obligations under the Capital Funds Agreement, to cover any shortfalls from payments received from AP&L, LP&L, MP&L, and NOPSI under these agreements.

Unit Power Sales Agreement

System Energy has agreed to sell all of its 90% owned and leased share of capacity and energy from Grand Gulf 1 to AP&L, LP&L, MP&L, and NOPSI in accordance with specified percentages (AP&L 36%, LP&L 14%, MP&L 33%, and NOPSI 17%) as ordered by FERC. Charges under this agreement are paid in consideration for the respective entitlements of AP&L, LP&L, MP&L, and NOPSI to receive capacity and energy, and are payable irrespective of the quantity of energy delivered so long as the unit remains in commercial operation. The agreement will remain in effect until terminated by the parties and approved by FERC, most likely upon Grand Gulf 1's retirement from service. The monthly obligation for payments from AP&L, LP&L, MP&L, and NOPSI to System Energy is approximately $49 million.

Availability Agreement

AP&L, LP&L, MP&L, and NOPSI are individually obligated to make payments or subordinated advances to System Energy in accordance with stated percentages (AP&L 17.1%, LP&L 26.9%, MP&L 31.3%, and NOPSI 24.7%) in amounts that, when added to amounts received under the Unit Power Sales Agreement or otherwise, are adequate to cover all of System Energy's operating expenses as defined, including an amount sufficient to amortize Grand Gulf 2 over 27 years. System Energy has assigned its rights to payments and advances to certain creditors as security for certain obligations. Since commercial operation of Grand Gulf 1, payments under the Unit Power Sales Agreement have exceeded the amounts payable under the Availability Agreement. Accordingly, no payments have ever been required.

Reallocation Agreement

System Energy and AP&L, LP&L, MP&L, and NOPSI entered into the Reallocation Agreement relating to the sale of capacity and energy from the Grand Gulf Station and the related costs, in which LP&L, MP&L, and NOPSI agreed to assume all of AP&L's responsibilities and obligations with respect to the Grand Gulf Station under the Availability Agreement. FERC's decision allocating a portion of Grand Gulf 1 capacity and energy to AP&L supersedes the Reallocation Agreement as it relates to Grand Gulf 1. Responsibility for any Grand Gulf 2

amortization amounts has been individually allocated (LP&L 26.23%, MP&L 43.97%, and NOPSI 29.80%) under the terms of the Reallocation Agreement. However, the Reallocation Agreement does not affect AP&L's obligation to System Energy's lenders under the assignments referred to in the preceding paragraph. AP&L would be liable for its share of such amounts if LP&L, MP&L, and NOPSI were unable to meet their contractual obligations. No payments of any amortization amounts will be required as long as amounts paid to System Energy under the Unit Power Sales Agreement, including other funds available to System Energy, exceed amounts required under the Availability Agreement, which is expected to be the case for the foreseeable future.

Reimbursement Agreement

In December 1988, System Energy entered into two entirely separate, but identical, arrangements for the sales and leasebacks of an approximate aggregate 11.5% ownership interest in Grand Gulf 1 (see Note 8). In connection with the equity funding of the sale and leaseback arrangements, letters of credit are required to be maintained to secure certain amounts payable for the benefit of the equity investors by System Energy under the leases. The current letters of credit are effective until January 15, 1997.

Under the provisions of the Reimbursement Agreement, as amended, related to the letters of credit, System Energy has agreed to a number of covenants relating to the maintenance of certain capitalization and fixed charge coverage ratios. System Energy agreed, during the term of the Reimbursement Agreement, to maintain its equity at not less than 33% of its adjusted capitalization (as defined in the Reimbursement Agreement to include certain amounts not included in capitalization for financial statement purposes). In addition, System Energy must maintain, with respect to each fiscal quarter during the term of the Reimbursement Agreement, a ratio of adjusted net income to interest expense (calculated, in each case, as specified in the Reimbursement Agreement) of at least 1.60. As of December 31, 1994, System Energy's equity approximated 34.25% of its adjusted capitalization, and its fixed charge coverage ratio was 1.23.

As a result of the charges associated with an agreement with FERC settling a long-standing dispute involving income tax allocation procedures, System Energy has obtained the consent of certain banks (parties to the Reimbursement Agreement) to waive temporarily the fixed charge coverage covenant in the letters of credit and Reimbursement Agreement, until November 30, 1995. (See Note 2 for information on the FERC Settlement.) System Energy expects that upon expiration of the waiver period, it will be in compliance with the fixed charge coverage covenant. Absent a waiver, System Energy's failure to perform this covenant could cause a draw under the letters of credit and/or early termination of the letters of credit. If the letters of credit were not replaced in a timely manner, a default or early termination of System Energy's leases could result. Draws under the letters of credit must be repaid by System Energy within 5 days (or in some cases, 90 days) following the date of the drawing.

Nuclear Insurance

The Price-Anderson Act limits public liability for a single nuclear incident to approximately $8.92 billion as of December 31, 1994. System Energy has protection for this liability through a combination of private insurance (currently $200 million) and an industry assessment program. Under the assessment program, the maximum amount that would be required for each nuclear incident would be $79.3 million per reactor, payable at a rate of $10 million per licensed reactor per incident per year. As a co-licensee of Grand Gulf 1 with System Energy, SMEPA would share 10% of this obligation. System Energy has one licensed reactor. In addition, System Energy participates in a private insurance program which provides coverage for worker tort claims filed for bodily injury caused by radiation exposure. System Energy's maximum assessment under the program is an aggregate of approximately $3.2 million in the event losses exceed accumulated reserve funds.

System Energy on behalf of itself and other insured interests (including other co-owners of Grand Gulf 1) is a member of certain insurance programs that provide coverage for property damage, including decontamination and premature decommissioning expense. As of December 31, 1994, System Energy was insured against such losses up to $2.75 billion with $250 million of this amount designated to cover any shortfall in the NRC required decommission trust funding. Under the property damage insurance programs, System Energy could be subject to assessments if losses exceed the accumulated funds available to the insurers. As of December 31, 1994, the maximum amount of such possible assessments to System Energy was $29.7 million. Under its agreement with System Energy, SMEPA would share in System Energy's obligation.

The amount of property insurance presently carried by System Energy exceeds the NRC's minimum requirement for nuclear power plant licensees of $1.06 billion per site. NRC regulations provide that the proceeds of this insurance must be used, first, to place and maintain the reactor in a safe and stable condition and, second, to complete decontamination operations. Only after proceeds are dedicated for such use and regulatory approval is secured, would any remaining proceeds be made available for the benefit of plant owners or their creditors.

Spent Nuclear Fuel and Decommissioning Costs

System Energy provides for estimated future disposal costs for spent nuclear fuel in accordance with the Nuclear Waste Policy Act of 1982. System Energy entered into a contract with the DOE, whereby the DOE will furnish disposal service at a cost of one mill per net KWH generated and sold. The fees payable to the DOE may be adjusted in the future to assure full recovery. System Energy considers all costs incurred or to be incurred for the disposal of spent nuclear fuel to be proper components of nuclear fuel expense and recovers such costs in rates.

Delays have occurred in the DOE's program for the acceptance and disposal of spent nuclear fuel at a permanent repository. In a statement released February 17, 1993, the DOE asserted that it does not have a legal obligation to accept spent nuclear fuel without an operational repository for which it has not yet arranged. Currently the DOE projects it will begin to accept spent fuel no earlier than 2010. In the meantime, System Energy is responsible for spent fuel storage. Current on-site spent fuel pool storage capacity at Grand Gulf 1 is estimated to be sufficient until 2004. Thereafter, System Energy will provide additional storage capacity at an initial cost of $5 million to $10 million. In addition, approximately $3 million to $5 million will be required every four to five years subsequent to 2004 until the DOE's repository begins accepting Grand Gulf 1's spent fuel.

Entergy Operations and System Fuels joined in lawsuits against the DOE, seeking clarification of the DOE's responsibility to receive spent nuclear fuel beginning in 1998. The original suits, filed June 20, 1994, asked for a ruling stating that the Nuclear Waste Policy Act require the DOE to begin taking title to the spent fuel and to start removing it from nuclear power plants in 1998, a mandate for the DOE's nuclear waste management program to begin accepting fuel in 1998 and court monitoring of the program, and the potential for escrow of payments to the Nuclear Waste Fund instead of directly to the DOE.

Decommissioning costs were estimated to approximate $248.7 million in 1989 dollars for System Energy's 90% interest in Grand Gulf 1, based on a 1989 decommissioning cost study. However, as a result of the FERC Complaint Case settlement, the amount to be collected in rates for the total cost of decommissioning System Energy's 90% interest in Grand Gulf 1 was set at approximately $198 million (in 1989 dollars). System Energy completed an updated cost study in 1994 which reflected a decommissioning cost of $365.9 million (in 1993 dollars) for System Energy's 90% interest. A filing with FERC to request the updated decommissioning costs in rates is under consideration by System Energy. The amounts recovered in rates are deposited in external trust funds and reported at market value. The accumulated decommissioning liability of $31.9 million as of December 31,

1994, has been recorded in other deferred credits. Decommissioning expense in the amount of $5.2 million was recorded in 1994. The actual decommissioning costs may vary from the estimates because of regulatory requirements, changes in technology, and increased costs of labor, materials, and equipment. Management believes that actual decommissioning costs are likely to be higher than the amounts presented above.

The staff of the SEC has questioned certain of the current accounting practices of the electric utility industry, regarding the recognition, measurement, and classification of decommissioning costs for nuclear generating stations in the financial statements of electric utilities. In response to these questions, the FASB is currently reviewing the accounting for decommissioning. If current electric utility industry accounting practices for such decommissioning are changed, annual provisions for decommissioning could increase, the estimated cost for decommissioning could be recorded as a liability rather than as accumulated depreciation, and trust fund income from the external decommissioning trusts could be reported as investment income rather than as a reduction to decommissioning expense.

The EPAct has a provision that assesses domestic nuclear utilities with fees for the decontamination and decommissioning of DOE's past uranium enrichment operations. The decontamination and decommissioning provisions will be used to set up a fund into which contributions from utilities and the federal government will be placed. System Energy's annual assessment, which will be adjusted annually for inflation, is approximately $1.4 million (in 1995 dollars) for approximately 15 years. FERC requires that utilities treat these assessments as costs of fuel as they are amortized. The cumulative liability of $15.8 million as of December 31, 1994, is recorded in other current liabilities and other non-current liabilities, according to FERC guidelines, and is offset in the financial statements by a regulatory asset.

System Fuels

System Fuels entered into a revolving credit agreement with a bank that provides $45 million in borrowings to finance System Fuels' nuclear materials and services inventory. Should System Fuels default on its obligations under its credit agreement, AP&L, LP&L, and System Energy have agreed to purchase the nuclear materials and services financed under the agreement.

NOTE 8. LEASES

Nuclear Fuel Lease

System Energy has an arrangement to lease nuclear fuel in an aggregate amount up to $105 million. The lessor finances its acquisition of nuclear fuel through a credit agreement and the issuance of notes. The credit agreement which was entered into in 1989 has been extended to February 1998 and the notes have varying remaining maturities of up to 3 years. It is expected that the credit arrangements will be extended or alternative financing will be secured by the lessor upon the maturity of the current arrangements. If the lessor cannot arrange for alternative financing upon maturity of its borrowings, System Energy must purchase nuclear fuel in an amount sufficient to enable the lessor to retire such borrowings.

Lease payments are based on nuclear fuel use. Nuclear fuel lease expense of $37.8 million, $36.2 million, and $48.4 million (including interest of $6.8 million, $5.1 million, and $8.5 million) was charged to operations in 1994, 1993, and 1992, respectively.

Sale and Leaseback Transactions

On December 28, 1988, System Energy entered into two entirely separate, but identical, arrangements for the sales and leasebacks of an approximate aggregate 11.5% undivided ownership interest in Grand Gulf 1 for an aggregate cash consideration of $500 million. System Energy is leasing back the undivided interest on a net lease basis over a 26 1/2-year basic lease term. System Energy has options to terminate the leases and to repurchase the undivided interest in Grand Gulf 1 at certain intervals during the basic lease term. Further, at the end of the basic lease term, System Energy has an option to renew the leases or to repurchase the undivided interest in Grand Gulf 1. See Note 7 with respect to certain other terms of the transactions.

On January 18, 1994, System Energy refinanced the debt portion of the sale and leaseback arrangements of the undivided portions of Grand Gulf 1. The secured lease obligation bonds of $356 million, 7.43% series due 2011, and $79 million, 8.2% series due 2014, will be indirectly secured by liens on, and a security interest in, certain ownership interests and the respective leases relating to Grand Gulf 1. See Note 7 for information on letters of credit maintained by System Energy for the benefit of the equity investors in the transactions.

In accordance with SFAS 98, "Accounting for Leases," due to "continuing involvement" by System Energy, the sale and leaseback arrangements of the undivided portions of Grand Gulf 1, as described above, are required to be reflected for financial reporting purposes as financing transactions in System Energy's financial statements. The amounts charged to expense for financial reporting purposes include the interest portion of the lease obligations and depreciation of the plant. However, operating revenues include the recovery of the lease payments because the transactions are accounted for as sales and leasebacks for rate-making purposes. The total of interest and depreciation expense exceeds the corresponding revenues realized during the early part of the lease term. Consistent with a recommendation contained in a FERC audit report, System Energy recorded as a deferred asset the difference between the recovery of the lease payments and the amounts expensed for interest and depreciation and is recording such difference as a deferred asset on an ongoing basis. The amount of this deferred asset was $78.5 million and $71.2 million as of December 31, 1994 and 1993, respectively. See Note 1 for further information regarding the accounting for the sale and leaseback transactions.

As of December 31, 1994, System Energy had future minimum lease payments (reflecting an implicit rate of 7.02% after the above refinancing) as follows (in thousands):

1995	$ 42,464
1996	42,753
1997	42,753
1998	42,753
1999	42,753
Years thereafter	802,820
Total	$ 1,016,296

NOTE 9. POSTRETIREMENT BENEFITS

Pension Plan

System Energy participates in a defined benefit pension plan sponsored by Entergy. Effective June 1990, all of System Energy's employees became employees of Entergy Operations. However, the employees still remain under System Energy's plan and no transfers of related pension liabilities and assets have been made. The pension

plan, which covers substantially all of its employees, is noncontributory and provides pension benefits based on employees' credited service and average compensation, generally during the last five years before retirement. System Energy funds pension costs in accordance with contribution guidelines established by the Employee Retirement Income Security Act of 1974, as amended, and the Internal Revenue Code of 1986, as amended. The assets of the plan consist primarily of common and preferred stocks, fixed income securities, interest in a money market fund, and insurance contracts.

System Energy's 1994, 1993, and 1992 pension cost, including amounts capitalized, included the following components:

	For the Years Ended December 31,		
	1994	1993	1992
	(In Thousands)		
Service cost - benefits earned during the period	$ 2,619	$ 2,045	$ 1,737
Interest cost on projected benefit obligation	2,148	1,709	1,439
Actual return on plan assets	498	(3,828)	(2,070)
Net amortization and deferral	(3,535)	972	(587)
Net pension cost	$ 1,730	$ 898	$ 519

The funded status of System Energy's pension plan as of December 31, 1994 and 1993, was:

	1994	1993
	(In Thousands)	
Actuarial present value of accumulated pension plan benefits:		
Vested	$ 13,305	$ 16,728
Nonvested	986	615
Accumulated benefit obligation	$ 14,291	$ 17,343
Plan assets at fair value	$ 33,285	$ 33,914
Projected benefit obligation	27,239	28,933
Plan assets in excess of projected benefit obligation	6,046	4,981
Unrecognized prior service cost	1,242	879
Unrecognized transition asset	(6,484)	(7,080)
Unrecognized net loss (gain)	(1,952)	1,802
Accrued pension asset	$ (1,148)	$ 582

The significant actuarial assumptions used in computing the information above for 1994, 1993, and 1992, were as follows: weighted average discount rate, 8.5% for 1994, 7.5% for 1993 and 8.25% for 1992; weighted average rate of increase in future compensation levels, 5.1% for 1994 and 5.6% for 1993 and 1992; and expected long-term rate of return on plan assets, 8.5%. Transition assets are being amortized over the average remaining service period of active participants.

NOTE 10. TRANSACTIONS WITH AFFILIATES

System Energy sells all of the capacity and energy from its share of Grand Gulf 1 to AP&L, LP&L, MP&L, and NOPSI under rate schedules approved by FERC. Accordingly, all of System Energy's operating revenues consist of billings to AP&L, LP&L, MP&L, and NOPSI.

MP&L provides a minimal amount of technical and advisory services and other miscellaneous services to System Energy. In addition, pursuant to a service agreement, System Energy receives technical and advisory services from Entergy Services. Charges from MP&L and Entergy Services for technical, advisory and miscellaneous services amounted to approximately $10.5 million in 1994, $12.3 million in 1993, and $13.8 million in 1992. System Energy pays directly or reimburses Entergy Operations for the costs associated with operating Grand Gulf 1 (excluding nuclear fuel) which were approximately $179.6 million in 1994, $151.3 million in 1993, and $179 million in 1992.

In addition, certain materials and services required for fabrication of nuclear fuel are acquired and financed by System Fuels and then sold to System Energy as needed. Charges for these materials and services, which represent additions to nuclear fuel, amounted to approximately $27.8 million in 1994, $32.8 million in 1993, and $13.7 million in 1992.

NOTE 11. QUARTERLY FINANCIAL DATA (UNAUDITED)

Operating results for the four quarters of 1994 and 1993 were:

	Operating Revenue	Operating Income (Loss)	Net Income (Loss)
		(In Thousands)	
1994:			
First Quarter	$ 147,847	$ 64,342	$ 21,549
Second Quarter	$ 151,219	$ 65,779	$ 25,212
Third Quarter	$ 150,949	$ 65,869	$ 24,934
Fourth Quarter	$ 24,948	$(24,223)	$(66,288)
1993:			
First Quarter	$ 164,630	$ 76,331	$ 31,782
Second Quarter	$ 153,527	$ 65,539	$ 21,268
Third Quarter	$ 155,071	$ 63,992	$ 23,040
Fourth Quarter	$ 177,540	$ 66,340	$ 17,837

See Note 2 for information regarding the recording of refunds in connection with the FERC Settlement in November 1994.

See Note 2 for information regarding the recording of refunds as a result of the FERC Return on Equity Case settlement in the third quarter of 1993.

SYSTEM ENERGY RESOURCES, INC.

SELECTED FINANCIAL DATA - FIVE-YEAR COMPARISON

	1994	1993	1992	1991	1990
	(Dollars in Thousands)				
Operating revenues	$ 474,963	$ 650,768	$ 723,410	$ 686,664	$ 801,618
Net income	$ 5,407	$ 93,927	$ 130,141	$ 104,622	$ 168,677
Total assets	$3,613,359	$3,891,066	$3,672,441	$3,642,203	$3,883,241
Long-term obligations (1)	$1,456,993	$1,536,593	$1,768,299	$1,707,470	$1,849,000
Electric energy sales (Millions of KWH)	8,653	7,113	7,354	8,220	6,666

(1) Includes long-term debt (excluding current maturities) and noncurrent capital lease obligations.

See Note 2 for information with respect to refunds and charges resulting from the FERC Settlement in 1994 and Note 3 for the effect of the accounting change for income taxes in 1993.

Item 9. Changes In and Disagreements With Accountants On Accounting and Financial Disclosure.

No event that would be described in response to this item has occurred with respect to Entergy, System Energy, AP&L, GSU, LP&L, MP&L, or NOPSI.

PART III

Item 10. Directors and Executive Officers of the Registrants.

All officers and directors listed below held the specified positions with their respective companies as of the date of filing this report.

ENTERGY CORPORATION

Directors

Information required by this item concerning directors of Entergy Corporation is set forth under the heading "Election of Directors" contained in the Proxy Statement of Entergy Corporation to be filed in connection with its Annual Meeting of Stockholders to be held May 26, 1995, and is incorporated herein by reference.

Name	Age	Position	Period
Officers			
Edwin Lupberger(a)	58	Chairman of the Board and Chief Executive Officer of Entergy Corporation	1985-Present
		Chairman of the Board and Chief Executive Officer of AP&L, LP&L, MP&L, and NOPSI	1993-Present
		Chairman of the Board and Chief Executive Officer of GSU	1994-Present
		Chairman of the Board of System Energy and Entergy Enterprises	1986-Present
		Chairman of the Board of Entergy Operations	1990-Present
		Chairman of the Board of Entergy Services	1985-Present
		Chief Executive Officer of Entergy Services	1991-Present
		President of Entergy Services and Entergy Enterprises	1994-Present
		Director of AP&L, LP&L, MP&L, NOPSI, and System Energy	1986-Present
		Director of Entergy Operations and Entergy Services	1994-Present
		Director of Entergy Enterprises	1984-Present
		Chief Executive Officer of Entergy Power, Entergy Power Development Corporation, and Entergy-Richmond Power Corporation	1993-Present
		Chief Executive Officer of Entergy Pakistan, Ltd. and Entergy Power Asia, Ltd.	1994-Present
		President of Entergy Corporation	1985-1991
		Chairman of the Board of Entergy Power	1990-1993
		Chief Executive Officer of Entergy Enterprises	1991-1994
		President of Entergy Services and Entergy Enterprises	1990-1991
		Chairman of the Board of System Fuels	1986-1990
		Director of System Fuels	1986-1992

Name	Age	Position	Period
Jerry L. Maulden	58	President and Chief Operating Officer of Entergy Corporation	1993-Present
		Vice Chairman and Chief Operating Officer of AP&L, GSU, LP&L, MP&L, and NOPSI	1993-Present
		Director of AP&L	1979-Present
		Director of GSU	1993-Present
		Director of LP&L and NOPSI	1991-Present
		Director of MP&L	1988-Present
		Director of Entergy Operations	1990-Present
		Director of System Energy	1987-Present
		Vice Chairman of Entergy Services	1992-Present
		Director of Entergy Services	1979-Present
		Chairman of the Board of AP&L	1989-1993
		Chief Executive Officer of AP&L	1979-1993
		Chairman of the Board and Chief Executive Officer of LP&L and NOPSI	1991-1993
		Chairman of the Board and Chief Executive Officer of MP&L	1989-1993
		Group President, System Executive - Transmission, Distribution, and Customer Service of Entergy Corporation	1991-1993
		Senior Vice President, System Executive - Arkansas/Mississippi/Missouri Division of Entergy Corporation	1988-1991
		Director of System Fuels	1979-1992
		Group President, System Executive - Transmission, Distribution, and Customer Service of Entergy Services	1991-1992
		Director of Entergy Enterprises	1984-1991
Jerry D. Jackson	50	Executive Vice President - Marketing and External Affairs of Entergy Corporation	1994-Present
		Executive Vice President - Marketing and External Affairs of AP&L, GSU, LP&L, MP&L, and NOPSI	1995-Present
		Executive Vice President - Marketing and External Affairs of Entergy Services	1994-Present
		Secretary of GSU	1994-1995
		Director of AP&L,LP&L, MP&L, and NOPSI	1992-Present
		Director of GSU	1994-Present
		Director of System Energy	1993-Present
		Director of Entergy Services	1990-Present
		Executive Vice President - Finance and External Affairs of Entergy Corporation	1990-1994
		Executive Vice President - Finance and External Affairs and Secretary of AP&L, LP&L, MP&L, and NOPSI	1992-1994
		Executive Vice President - Finance and External Affairs of GSU	1993-1994
		Executive Vice President - Finance and External Affairs of Entergy Services	1990-1992
		President and Chief Administrative Officer of Entergy Services	1992-1994
		Secretary of Entergy Corporation	1991-1994
		President of Entergy Enterprises	1991-1992
		Director of Entergy Power and Entergy Enterprises	1990-1992
		Senior Vice President, System Executive - Legal and External Affairs of Entergy Corporation and Entergy Services	1987-1990

Name	Age	Position	Period
Donald C. Hintz	52	Executive Vice President and Chief Nuclear Officer of Entergy Corporation	1994-Present
		Executive Vice President - Nuclear of AP&L, GSU, and LP&L	1994-Present
		Director of AP&L, LP&L, MP&L, System Energy, System Fuels, and Entergy Services	1992-Present
		Director of GSU	1993-Present
		Chief Executive Officer and President of System Energy and Entergy Operations	1992-Present
		Director of Entergy Operations	1990-Present
		Director of GSG&T, Prudential Oil & Gas, Southern Gulf Railway, and Varibus Corporation	1994-Present
		Senior Vice President and Chief Nuclear Officer of Entergy Corporation	1993-1994
		Senior Vice President - Nuclear of AP&L	1990-1994
		Senior Vice President - Nuclear of GSU	1993-1994
		Senior Vice President - Nuclear of LP&L	1992-1994
		Director of NOPSI	1992-1994
		President of Entergy Operations	1992-1992
		Chief Operating Officer and Executive Vice President of Entergy Operations	1990-1992
		Group Vice President - Nuclear of LP&L	1990-1992
		Chief Operating Officer and Executive Vice President of System Energy	1989-1990
Gerald D. McInvale	51	Senior Vice President and Chief Financial Officer of Entergy Corporation, AP&L, LP&L, MP&L, NOPSI, System Energy, Entergy Operations, Entergy Services, and Entergy Enterprises	1991-Present
		Senior Vice President and Chief Financial Officer of GSU	1993-Present
		Senior Vice President and Chief Financial Officer of System Fuels	1994-Present
		Vice President, Treasurer, and Director of Entergy Power	1993-Present
		Director of System Fuels	1992-Present
		Treasurer of Entergy Enterprises	1992-Present
		Director and Acting Chief Operating Officer of Entergy Enterprises	1994-Present
		Chairman of the Board of Entergy Systems and Service, Inc.	1994-Present
		Director of Entergy Systems and Service, Inc.	1993-Present
		Vice President, Treasurer, and Director of Entergy Power Development Corporation and Entergy-Richmond Power Corporation	1993-Present
		Senior Vice President, Treasurer, and Director of Entergy Pakistan, Ltd. and Entergy Power Asia, Ltd.	1994-Present
		President - Executive Information Strategies (Consulting Firm), Dallas, Texas	1990-1991
		Senior Vice President and Chief Financial Officer of Frito-Lay, Inc. (Subsidiary of PepsiCo, Inc.), Dallas, Texas	1987-1990
Michael G. Thompson	54	Senior Vice President and Chief Legal Officer of Entergy Corporation and Entergy Services	1992-Present
		Senior Vice President, Chief Legal Officer, and Secretary of Entergy Enterprises	1992-Present
		Senior Vice President, Secretary, and Director of Entergy Pakistan, Ltd. and Entergy Power Asia, Ltd.	1994-Present
		Vice President, Secretary, and Director of Entergy Power	1994-Present
		Vice President and Secretary of Entergy Systems and Service, Inc.	1993-Present
		Vice President, Secretary, and Director of Entergy Power Development and Entergy-Richmond Power Corporation	1992-Present
		Secretary of Entergy Corporation	1994-Present
		Secretary of AP&L, GSU, LP&L, MP&L, and NOPSI	1995-Present
		Director of Entergy Systems and Service, Inc.	1992-Present
		Senior Vice President and Chief Legal Officer of Entergy Power	1993-1994
		Assistant Secretary of Entergy Corporation	1993-1994
		Senior Partner of Friday, Eldredge & Clark (law firm)	1987-1992

Name	Age	Position	Period
S. M. Henry Brown, Jr.	56	Vice President - Federal Governmental Affairs of Entergy Corporation and Entergy Services	1989-Present
Charles L. Kelly	58	Vice President - Corporate Communications and Public Relations of Entergy Corporation	1992-Present
		Vice President - Corporate Communications and Public Relations of Entergy Services	1991-Present
		Vice President - Corporate Communications of AP&L	1981-1991
Lee W. Randall	45	Vice President and Chief Accounting Officer of Entergy Corporation, AP&L, LP&L, MP&L, NOPSI, System Energy, Entergy Operations, and Entergy Services	1991-Present
		Vice President, Chief Accounting Officer, and Assistant Secretary of GSU	1993-Present
		Assistant Secretary of AP&L, LP&L, MP&L, NOPSI, Entergy Operations, and Entergy Services	1991-Present
		Senior Vice President - Finance and Administration and Chief Financial Officer of AP&L	1988-1991
		Secretary of AP&L	1989-1991
		Assistant Treasurer of AP&L	1988-1991

ARKANSAS POWER & LIGHT COMPANY

Directors

Michael B. Bemis(b)	47	Executive Vice President - Customer Service and Director of AP&L, LP&L, and MP&L	1992-Present
		Executive Vice President - Customer Service of GSU	1993-Present
		Executive Vice President - Customer Service of NOPSI and Entergy Services	1992-Present
		Director of GSU	1994-Present
		Director of System Fuels	1992-Present
		Director of Varibus Corporation, Prudential Oil & Gas, Inc., GSG&T, Inc., and Southern Gulf Railway Company	1994-Present
		Director of NOPSI	1992-1994
		President and Chief Operating Officer of LP&L and NOPSI	1992-1992
		President and Chief Operating Officer of MP&L	1989-1991
		Secretary of MP&L	1991-1991
Donald C. Hintz	52	See the information under the Entergy Corporation Officers Section above, incorporated herein by reference.	
Jerry D. Jackson	50	See the information under the Entergy Corporation Officers Section above, incorporated herein by reference.	
R. Drake Keith	59	President and Director of AP&L	1989-Present
		Chief Operating Officer of AP&L	1989-1992
		Secretary of AP&L	1991-1992
Edwin Lupberger	58	See the information under the Entergy Corporation Officers Section above, incorporated herein by reference.	
Jerry L. Maulden	58	See the information under the Entergy Corporation Officers Section above, incorporated herein by reference.	

Officers

Edwin Lupberger	58	See the information under the Entergy Corporation Officers Section above, incorporated herein by reference.
Jerry L. Maulden	58	See the information under the Entergy Corporation Officers Section above, incorporated herein by reference.
R. Drake Keith	59	See the information under the AP&L Directors Section above, incorporated herein by reference.
Michael B. Bemis	47	See the information under the AP&L Directors Section above, incorporated herein by reference.

Name	Age	Position	Period
Jerry D. Jackson	50	See the information under the Entergy Corporation Officers Section above, incorporated herein by reference.	
Frank F. Gallaher	49	Executive Vice President - Fossil Operations of AP&L, LP&L, MP&L, NOPSI, and Entergy Services	1993-Present
		President of GSU	1994-Present
		Director of GSU	1993-Present
		Chairman of the Board of System Fuels	1992-Present
		Chairman of the Board of Varibus Corporation, Prudential Oil & Gas, Inc., GSG&T, Inc., and Southern Gulf Railway Company	1993-Present
		Director of Entergy Services and System Fuels	1992-Present
		Senior Vice President - Fossil Operations of AP&L, LP&L, MP&L, NOPSI, and Entergy Services	1992-1993
		Vice President and Chief Engineer of MP&L	1985-1990
		Vice President - System Planning of Entergy Services	1990-1992
Donald C. Hintz	52	See the information under the Entergy Corporation Officers Section above, incorporated herein by reference.	
Gerald D. McInvale	51	See the information under the Entergy Corporation Officers Section above, incorporated herein by reference.	
Michael G. Thompson	54	See the information under the Entergy Corporation Officers Section above, incorporated herein by reference.	
Michael R. Niggli	45	Senior Vice President - Marketing of AP&L, GSU, LP&L, MP&L, NOPSI, and Entergy Services	1993-Present
		Vice President - Customer Services of LP&L, NOPSI, and Entergy Services	1993-1993
		Vice President - Strategic Planning of Entergy Services	1990-1992
		Vice President - Fuels Management of Entergy Services	1988-1990
		Vice President and Director of Entergy Enterprises	1991-1992
Cecil L. Alexander(c)	59	Vice President - Governmental Affairs of AP&L	1991-Present
		Vice President - Public Affairs of AP&L	1989-1991
Richard J. Landy	49	Vice President - Human Resources and Administration of AP&L, LP&L, MP&L, NOPSI, Entergy Services, and EOI	1991-Present
		Vice President - Human Resources and Administration of GSU	1993-Present
		Vice President - Human Resources and Administration of System Energy	1986-1990
		Vice President - Human Resources and Administration of Entergy Operations	1990-1991
James S. Pilgrim	59	Vice President - Customer Service of AP&L	1994-Present
		Director, Central Region, TDCS Customer Service	1993-1994
		Central Division Manager of MP&L	1991-1993
		Northern Division Manager of MP&L	1988-1991
Lee W. Randall	45	See the information under the Entergy Corporation Officers Section above, incorporated herein by reference.	
C. Hiram Walters	58	Vice President - Customer Service of AP&L	1993-Present
		Vice President - Customer Service of LP&L	1994-Present
		Vice President - Customer Service, Central Region of Entergy Services	1993-Present
		Vice President - Customer Service of MP&L	1984-1991
		Senior Vice President - Customer Service of Entergy Services	1991-1992

GULF STATES UTILITIES COMPANY

Directors

Michael B. Bemis	47	See the information under the AP&L Directors Section above, incorporated herein by reference
Frank F. Gallaher	49	See the information under the AP&L Officers Section above, incorporated herein by reference
Donald C. Hintz	52	See the information under the Entergy Corporation Officers Section above, incorporated herein by reference.

Name	Age	Position	Period
Jerry D. Jackson	50	See the information under the Entergy Corporation Officers Section above, incorporated herein by reference.	
Edwin Lupberger	58	See the information under the Entergy Corporation Officers Section above, incorporated herein by reference.	
Jerry L. Maulden	58	See the information under the Entergy Corporation Officers Section above, incorporated herein by reference.	
Officers			
Edwin Lupberger	58	See the information under the Entergy Corporation Officers Section above, incorporated herein by reference.	
Jerry L. Maulden	58	See the information under the Entergy Corporation Officers Section above, incorporated herein by reference.	
Frank F. Gallaher	49	See the information under the AP&L Officers Section above, incorporated herein by reference.	
Michael B. Bemis	47	See the information under the AP&L Directors Section above, incorporated herein by reference.	
Jerry D. Jackson	50	See the information under the Entergy Corporation Officers Section above, incorporated herein by reference.	
Donald C. Hintz	52	See the information under the Entergy Corporation Officers Section above, incorporated herein by reference.	
Gerald D. McInvale	51	See the information under the Entergy Corporation Officers Section above, incorporated herein by reference.	
Michael G. Thompson	54	See the information under the Entergy Corporation Officers Section above, incorporated herein by reference.	
Michael R. Niggli	45	See the information under the AP&L Officers Section above, incorporated herein by reference.	
Richard J. Landy	49	See the information under the AP&L Officers Section above, incorporated herein by reference.	
William E. Colston	59	Vice President - Customer Service of GSU	1994-Present
		Vice President - Customer Service of LP&L	1993-Present
		Vice President - Customer Service of Southern Region of Entergy Services	1993-Present
		Vice President - Division Manager of LP&L	1988-1991
		Regional Director of LP&L	1992-1993
Calvin J. Hebert	60	Vice President - Customer Service of GSU	1993-Present
		Senior Vice President - Division Operations of GSU	1992-1993
		Senior Vice President - External Affairs of GSU	1986-1992
Karen Johnson	50	Vice President - Governmental Affairs of GSU - Texas	1994-Present
		Executive Director of State Bar of Texas	1990-1994
		Attorney at Law, Akin Gump Strauss Hauer & Feld	1983-1990
Lee W. Randall	45	See the information under the Entergy Corporation Officers Section above, incorporated herein by reference.	

LOUISIANA POWER & LIGHT COMPANY

Directors			
Michael B. Bemis	47	See the information under the AP&L Directors Section above, incorporated herein by reference.	
John J. Cordaro	61	President and Director of LP&L and NOPSI	1992-Present
		Group Vice President - External Affairs of LP&L and NOPSI	1989-1992
Donald C. Hintz	52	See the information under the Entergy Corporation Officers Section above, incorporated herein by reference.	
Jerry D. Jackson	50	See the information under the Entergy Corporation Officers Section above, incorporated herein by reference.	
Edwin Lupberger	58	See the information under the Entergy Corporation Officers Section above, incorporated herein by reference.	
Jerry L. Maulden	58	See the information under the Entergy Corporation Officers Section above, incorporated herein by reference.	

Name	Age	Position	Period
Officers			
Edwin Lupberger	58	See the information under the Entergy Corporation Officers Section above, incorporated herein by reference.	
Jerry L. Maulden	58	See the information under the Entergy Corporation Officers Section above, incorporated herein by reference.	
John J. Cordaro	61	See the information under the LP&L Directors Section above, incorporated herein by reference.	
Michael B. Bemis	47	See the information under the AP&L Directors Section above, incorporated herein by reference.	
Jerry D. Jackson	50	See the information under the Entergy Corporation Officers Section above, incorporated herein by reference.	
Frank F. Gallaher	49	See the information under the AP&L Officers Section above, incorporated herein by reference.	
Donald C. Hintz	52	See the information under the Entergy Corporation Officers Section above, incorporated herein by reference.	
Gerald D. McInvale	51	See the information under the Entergy Corporation Officers Section above, incorporated herein by reference.	
Michael G. Thompson	54	See the information under the Entergy Corporation Officers Section above, incorporated herein by reference.	
Michael R. Niggli	45	See the information under the AP&L Officers Section above, incorporated herein by reference.	
Richard C. Guthrie	52	Vice President - Governmental Affairs of LP&L and NOPSI	1992-Present
		Vice President - Public Affairs of LP&L and NOPSI	1986-1992
Richard J. Landy	49	See the information under the AP&L Officers Section above, incorporated herein by reference.	
James D. Bruno	55	Vice President - Customer Service of LP&L and NOPSI	1994-Present
		Vice President - Metro Region of Entergy Services	1993-Present
		Region Director - Metro Region of Entergy Services	1991-1993
		Vice President - Division Manager - Orleans Division of Entergy Services	1988-1991
William E. Colston	59	See the information under the GSU Officers Section above, incorporated herein by reference.	
Lee W. Randall	45	See the information under the Entergy Corporation Officers Section above, incorporated herein by reference.	
C. Hiram Walters	58	See the information under the AP&L Officers Section above, incorporated herein by reference.	

MISSISSPPI POWER & LIGHT COMPANY

Directors			
Michael B. Bemis	47	See the information under the AP&L Directors Section above, incorporated herein by reference.	
Donald C. Hintz	52	See the information under the Entergy Corporation Officers Section above, incorporated herein by reference.	
Jerry D. Jackson	50	See the information under the Entergy Corporation Officers Section above, incorporated herein by reference.	
Edwin Lupberger	58	See the information under the Entergy Corporation Officers Section above, incorporated herein by reference.	
Jerry L. Maulden	58	See the information under the Entergy Corporation Officers Section above, incorporated herein by reference.	
Donald E. Meiners(d)	59	President and Director of MP&L	1992-Present
		Senior Vice President, System Executive - Services Division of Entergy Corporation	1988-1990
		President and Chief Operating Officer of LP&L and NOPSI	1990-1991
		Chief Operating Officer and Secretary of MP&L	1992-1992
		President and Chief Executive Officer of Entergy Services, System Fuels, and Entergy Enterprises	1987-1990

Name	Age	Position	Period
Officers			
Edwin Lupberger	58	See the information under the Entergy Corporation Officers Section above, incorporated herein by reference.	
Jerry L. Maulden	58	See the information under the Entergy Corporation Officers Section above, incorporated herein by reference.	
Donald E. Meiners	59	See the information under the MP&L Directors Section above, incorporated herein by reference.	
Michael B. Bemis	47	See the information under the AP&L Directors Section above, incorporated herein by reference.	
Jerry D. Jackson	50	See the information under the Entergy Corporation Officers Section above, incorporated herein by reference.	
Frank F. Gallaher	49	See the information under the AP&L Officers Section above, incorporated herein by reference.	
Gerald D. McInvale	51	See the information under the Entergy Corporation Officers Section above, incorporated herein by reference.	
Michael G. Thompson	54	See the information under the Entergy Corporation Officers Section above, incorporated herein by reference.	
Michael R. Niggli	45	See the information under the AP&L Officers Section above, incorporated herein by reference.	
Bill F. Cossar	56	Vice President - Governmental Affairs of MP&L	1987-Present
Johnny D. Ervin	45	Vice President - Customer Service of MP&L	1991-Present
		Director of Entergy Enterprises	1991-1992
		Vice President - Marketing of LP&L and NOPSI	1988-1991
		Vice President - Division Manager of LP&L	1989-1991
Richard J. Landy	49	See the information under the AP&L Officers Section above, incorporated herein by reference.	
Lee W. Randall	45	See the information under the Entergy Corporation Officers Section above, incorporated herein by reference.	

NEW ORLEANS PUBLIC SERVICE INC.

Directors			
John J. Cordaro	61	See the information under the LP&L Directors Section above, incorporated herein by reference.	
Jerry D. Jackson	50	See the information under the Entergy Corporation Officers Section above, incorporated herein by reference.	
Edwin Lupberger	58	See the information under the Entergy Corporation Officers Section above, incorporated herein by reference.	
Jerry L. Maulden	58	See the information under the Entergy Corporation Officers Section above, incorporated herein by reference.	
Officers			
Edwin Lupberger	58	See the information under the Entergy Corporation Officers Section above, incorporated herein by reference.	
Jerry L. Maulden	58	See the information under the Entergy Corporation Officers Section above, incorporated herein by reference.	
John J. Cordaro	61	See the information under the LP&L Directors Section above, incorporated herein by reference.	
Michael B. Bemis	47	See the information under the AP&L Directors Section above, incorporated herein by reference.	
Jerry D. Jackson	50	See the information under the Entergy Corporation Officers Section above, incorporated herein by reference.	
Frank F. Gallaher	49	See the information under the AP&L Officers Section above, incorporated herein by reference.	
Gerald D. McInvale	51	See the information under the Entergy Corporation Officers Section above, incorporated herein by reference.	
Michael G. Thompson	54	See the information under the Entergy Corporation Officers Section above, incorporated herein by reference.	

Name	Age	Position	Period
Michael R. Niggli	45	See the information under the AP&L Officers Section above, incorporated herein by reference.	
Richard C. Guthrie	52	See the information under the LP&L Officers Section above, incorporated herein by reference.	
Daniel F. Packer	47	Vice President - Regulatory and Governmental Affairs of NOPSI	1994-Present
		General Manager - Plant Operations at Waterford 3	1991-1994
		Manager - Operations and Maintenance at Waterford 3	1990-1991
Richard J. Landy	49	See the information under the AP&L Officers Section above, incorporated herein by reference.	
James D. Bruno	55	See the information under the LP&L Officers Section above, incorporated herein by reference.	
Lee W. Randall	45	See the information under the Entergy Corporation Officers Section above, incorporated herein by reference.	

SYSTEM ENERGY RESOURCES, INC.

Directors

Donald C. Hintz	52	See the information under the Entergy Corporation Officers Section above, incorporated herein by reference.	
Jerry D. Jackson	50	See the information under the Entergy Corporation Officers Section above, incorporated herein by reference.	
Edwin Lupberger	58	See the information under the Entergy Corporation Officers Section above, incorporated herein by reference.	
Jerry L. Maulden	58	See the information under the Entergy Corporation Officers Section above, incorporated herein by reference.	

Officers

Edwin Lupberger	58	See the information under the Entergy Corporation Officers Section above, incorporated herein by reference.	
Donald C. Hintz	52	See the information under the Entergy Corporation Officers Section above, incorporated herein by reference.	
Gerald D. McInvale	51	See the information under the Entergy Corporation Officers Section above, incorporated herein by reference.	
Lee W. Randall	45	See the information under the Entergy Corporation Officers Section above, incorporated herein by reference.	
Joseph L. Blount	48	Secretary of System Energy and Entergy Operations	1991-Present
		Vice President Legal and External Affairs of System Energy	1989-1990
		Vice President Legal and External Affairs of Entergy Operations	1990-1993
		Assistant Secretary for System Energy	1987-1991
		Assistant Secretary for Entergy Operations	1990-1991

(a) Mr. Lupberger is a director of First Commerce Corporation, New Orleans, LA, International Shipholding Corporation, New Orleans, LA, and First National Bank of Commerce, New Orleans, LA.

(b) Mr. Bemis is a director of Deposit Guaranty National Bank, Jackson, MS and Deposit Guaranty Corporation, Jackson, MS.

(c) Mr. Alexander is a director of First National Bank of Cleburne County, Heber Springs, AR.

(d) Mr. Meiners is a director of Trustmark National Bank, Jackson, MS, and Trustmark Corporation, Jackson, MS.

Each director and officer of the applicable System company is elected yearly to serve until the first Board Meeting following the Annual Meeting of Stockholders and until a successor is elected and qualified. Annual meetings are currently expected to be held as follows:

Entergy Corporation - May 26, 1995
AP&L - May 17, 1995
GSU - May 17, 1995
LP&L - May 17, 1995
MP&L - May 17, 1995
NOPSI - May 17, 1995
System Energy - April 14, 1995

Directorships shown above are generally limited to entities subject to Section 12 or 15(d) of the Securities and Exchange Act of 1934 or to the Investment Company Act of 1940.

Section 16(a) of the Securities Exchange Act of 1934 and Section 17(a) of the Public Utility Holding Company Act of 1935 require each registrant's officers, directors and persons who own more than 10% of a registered class of such registrant's equity securities to file reports of ownership and changes in ownership concerning the securities of Entergy Corporation and its subsidiaries with the SEC and to furnish Entergy Corporation with copies of all Section 16(a) and 17(a) forms they file. Shortly following the Merger, certain individuals were elected as officers of GSU. Although none of these individuals owned any reportable securities of GSU, their initial Forms 3 for GSU were not timely filed. These officers of GSU were: Michael B. Bemis, Frank F. Gallaher, Glenn E. Harder, Donald C. Hintz, Jerry D. Jackson, Richard J. Landy, Edwin Lupberger, Jerry L. Maulden, Gerald D. McInvale, Michael R. Niggli, and Lee W. Randall. Four individuals considered officers of the Corporation for purposes of Section 16 failed to report on their 1993 Forms 5 their receipt during 1993 of certain restricted shares of the Corporation's stock under the Equity Ownership Plan. These individuals and their respective unreported shares were: S.M. Henry Brown, 4,000 shares; Frank F. Gallaher, 4,000 shares; Charles L. Kelly, 4,000 shares, and Edwin Lupberger, 5,000 shares. Glenn E. Harder, a former officer of the Corporation, failed to timely report on a Form 4 the sale in October 1994 of 15 shares of the Corporation's stock which he had held in the Corporation's dividend reinvestment plan. Each of the above transactions has now been correctly reported.

Item 11. Executive Compensation

ENTERGY CORPORATION

Information called for by this item concerning the directors and officers of Entergy Corporation and the Personnel Committee of Entergy Corporation's Board of Directors is set forth under the headings "Executive Compensation" and "Personnel Committee Interlocks and Insider Participation" contained in the Proxy Statement of Entergy Corporation to be filed in connection with its Annual Meeting of Stockholders to be held on May 26, 1995, which information is incorporated herein by reference.

Summary Compensation Tables

The following tables include the Chief Executive Officers and the four other most highly compensated executive officers in office as of December 31, 1994 at AP&L, GSU, LP&L, MP&L, NOPSI, and System Energy. This determination was based on total annual base salary and bonuses (excluding bonuses of an extraordinary and nonrecurring nature) from all System sources earned by each officer during the year 1994. See Item 10, "Directors and Executive Officers of the Registrants," incorporated herein by reference, for information on the principal positions of the executive officers named in the table below.

AP&L, GSU, LP&L, MP&L, NOPSI, and System Entergy

As shown in Item 10, most executive officers named below are employed by several System companies. Because it would be impracticable to allocate such officers' salaries among the various companies, the table below includes aggregate compensation paid by all System companies.

		Annual Compensation			Long-Term Compensation: Awards		Long-Term Compensation: Payouts	
Name	Year	Salary	(a) Bonus	Other Annual Compensation	Restricted Stock Awards	Securities Underlying Options	(b) LTIP Payouts	(c) All Other Compensation
Michael B. Bemis	1994	$288,846	$ 76,923	$ 32,940	(d)	2,500 shares	$ 28,275	$22,982
	1993	258,538	161,142	62,372	(d)	2,500	50,125	74,619
	1992	258,059	170,186	35,927	(d)	2,500	45,094	71,492
Joseph L. Blount	1994	$115,171	$ 17,064	$ 9,339	(d)	0 shares	0	$12,416
	1993	109,090	0	4,416	(d)	0	0	15,926
	1992	109,140	13,435	5,092	(d)	0	0	17,591
Donald C. Hintz*	1994	$320,769	$142,749	$ 52,389	(d)	5,000 shares	$ 48,379	$23,056
	1993	265,386	166,560	48,548	(d)	5,000	85,774	24,462
	1992	228,024	114,822	38,364	(d)	2,500	77,165	24,205
Jerry D. Jackson	1994	$323,711	$106,155	$ 29,598	(d)	5,000 shares	$ 56,550	$23,370
	1993	288,559	217,287	36,166	(d)	6,719	100,250	25,961
	1992	254,167	152,500	27,008	(d)	5,000	90,188	25,447
Edwin Lupberger**	1994	$681,539	$218,789	$ 39,961	(d)	10,000 shares	$139,525	$29,457
	1993	542,077	437,610	20,327	(d)	13,438	248,313	32,957
	1992	527,499	374,100	39,760	(d)	10,000	180,375	33,671
Jerry L. Maulden	1994	$426,134	$135,962	$ 63,994	(d)	5,000 shares	$ 56,550	$25,690
	1993	385,000	286,985	84,655	(d)	5,000	100,250	25,639
	1992	392,233	259,316	79,280	(d)	5,000	90,188	24,920
Gerald D. McInvale	1994	$244,165	$ 66,227	$ 14,146	(d)	2,500 shares	$ 28,275	$19,581
	1993	221,696	141,811	48,805	(d)	2,500	50,125	22,667
	1992	209,975	93,686	45,585	(d)	2,500	45,094	43,594
Lee W. Randall	1994	$177,001	$ 36,392	$ 7,208	(d)	0 shares	$ 0	$14,271
	1993	176,321	57,142	8,014	(d)	0	0	17,986
	1992	168,859	37,094	6,818	(d)	0	0	19,555

* Chief Executive Officer of System Energy.

** Chief Executive Officer of AP&L, GSU, LP&L, MP&L, and NOPSI.

(a) Includes bonuses earned pursuant to the Annual Incentive Plan as well as any bonuses of an extraordinary or nonrecurring nature.

(b) Amounts include the value of restricted shares that vested under Entergy's Equity Ownership Plan.

(c) Includes the following:

(1) 1994 Executive Medical Plan premiums of $1,761 for each of the above-named executives in 1994.

(2) 1994 employer contributions to the Defined Contribution Restoration Plan as follows: Mr. Bemis $4,096; Mr. Hintz $5,210; Mr. Jackson $5,134; Mr. Lupberger $15,946; Mr. Maulden $8,359; Mr. McInvale $2,775; Mr. Randall $810.

(3) 1994 employer contributions to the System Savings Plan as follows: Mr. Bemis $4,500; Mr. Blount $3,455; Mr. Hintz $4,500; Mr. Jackson $4,500; Mr. Lupberger $4,500; Mr. Maulden $4,500; Mr. McInvale $4,500; Mr. Randall $4,500.

(4) 1994 reimbursements under the Executive Financial Counseling Program as follows: Mr. Bemis $2,725; Mr. Hintz $785; Mr. Jackson $1,175; Mr. Lupberger $2,623; Mr. Maulden $1,350; Mr. McInvale $645.

(5) 1994 payments for personal use under the Private Ownership Vehicle Plan as follows: Mr. Bemis $9,900; Mr. Blount $7,200; Mr. Hintz $10,800; Mr. Jackson $10,800; Mr. Lupberger $4,627; Mr. Maulden $9,720; Mr. McInvale $9,900; Mr. Randall $7,200.

(d) Restricted stock awarded under the Equity Ownership Plan is subject to performance based criteria. Restricted stock awards in 1994 are reported under the "Long-Term Incentive Plan Awards" table, and reference is made to this table for information on the aggregate number of restricted shares awarded during 1994 and the vesting schedule for such shares. At December 31, 1994, the number and value of the aggregate restricted stock holdings were as follows: Mr. Bemis: 12,750 shares, $278,907; Mr. Hintz: 17,568 shares, $384,300; Mr. Jackson: 18,000 shares, $393,750; Mr. Lupberger: 33,950 shares, $742,657; Mr. Maulden: 18,000 shares, $393,750; and Mr. McInvale: 12,750 shares, $278,907. Accumulated dividends are paid on restricted stock when vested. The value of stock for which restrictions were lifted in 1994, and the applicable portion of accumulated cash dividends, are reported in the LTIP Payouts column in the above table. The value of restricted stock awards as of December 31, 1994 are determined by multiplying the total number of shares awarded by the closing market price of Entergy Corporation common stock on the New York Stock Exchange Composite Transactions on December 31, 1994 ($21.875 per share).

Summary Compensation Tables

The following tables include the Chief Executive Officers and the four other most highly compensated executive officers in office as of December 31, 1994 at AP&L, GSU, LP&L, MP&L, NOPSI, and System Energy. This determination was based on total annual base salary and bonuses (excluding bonuses of an extraordinary and nonrecurring nature) from all System sources earned by each officer during the year 1994. See Item 10, "Directors and Executive Officers of the Registrants," incorporated herein by reference, for information on the principal positions of the executive officers named in the table below.

AP&L, GSU, LP&L, MP&L, NOPSI, and System Entergy

As shown in Item 10, most executive officers named below are employed by several System companies. Because it would be impracticable to allocate such officers' salaries among the various companies, the table below includes aggregate compensation paid by all System companies.

		Annual Compensation			Long-Term Compensation			
					Awards		Payouts	
Name	Year	Salary	(a) Bonus	Other Annual Compensation	Restricted Stock Awards	Securities Underlying Options	(b) LTIP Payouts	(c) All Other Compensation
Michael B. Bemis	1994	$288,846	$ 76,923	$ 32,940	(d)	2,500 shares	$ 28,275	$22,982
	1993	258,538	161,142	62,372	(d)	2,500	50,125	74,619
	1992	258,059	170,186	35,927	(d)	2,500	45,094	71,492
Joseph L. Blount	1994	$115,171	$ 17,064	$ 9,339	(d)	0 shares	0	$12,416
	1993	109,090	0	4,416	(d)	0	0	15,926
	1992	109,140	13,435	5,092	(d)	0	0	17,591
Donald C. Hintz*	1994	$320,769	$142,749	$ 52,389	(d)	5,000 shares	$ 48,379	$23,056
	1993	265,386	166,560	48,548	(d)	5,000	85,774	24,462
	1992	228,024	114,822	38,364	(d)	2,500	77,165	24,205
Jerry D. Jackson	1994	$323,711	$106,155	$ 29,598	(d)	5,000 shares	$ 56,550	$23,370
	1993	288,559	217,287	36,166	(d)	6,719	100,250	25,961
	1992	254,167	152,500	27,008	(d)	5,000	90,188	25,447
Edwin Lupberger**	1994	$681,539	$218,789	$ 39,961	(d)	10,000 shares	$139,525	$29,457
	1993	542,077	437,610	20,327	(d)	13,438	248,313	32,957
	1992	527,499	374,100	39,760	(d)	10,000	180,375	33,671
Jerry L. Maulden	1994	$426,134	$135,962	$ 63,994	(d)	5,000 shares	$ 56,550	$25,690
	1993	385,000	286,985	84,655	(d)	5,000	100,250	25,639
	1992	392,233	259,316	79,280	(d)	5,000	90,188	24,920
Gerald D. McInvale	1994	$244,165	$ 66,227	$ 14,146	(d)	2,500 shares	$ 28,275	$19,581
	1993	221,696	141,811	48,805	(d)	2,500	50,125	22,667
	1992	209,975	93,686	45,585	(d)	2,500	45,094	43,594
Lee W. Randall	1994	$177,001	$ 36,392	$ 7,208	(d)	0 shares	$ 0	$14,271
	1993	176,321	57,142	8,014	(d)	0	0	17,986
	1992	168,859	37,094	6,818	(d)	0	0	19,555

* Chief Executive Officer of System Energy.

** Chief Executive Officer of AP&L, GSU, LP&L, MP&L, and NOPSI.

(a) Includes bonuses earned pursuant to the Annual Incentive Plan as well as any bonuses of an extraordinary or nonrecurring nature.

(b) Amounts include the value of restricted shares that vested under Entergy's Equity Ownership Plan.

(c) Includes the following:

(1) 1994 Executive Medical Plan premiums of $1,761 for each of the above-named executives in 1994.

(2) 1994 employer contributions to the Defined Contribution Restoration Plan as follows: Mr. Bemis $4,096; Mr. Hintz $5,210; Mr. Jackson $5,134; Mr. Lupberger $15,946; Mr. Maulden $8,359; Mr. McInvale $2,775; Mr. Randall $810.

(3) 1994 employer contributions to the System Savings Plan as follows: Mr. Bemis $4,500; Mr. Blount $3,455; Mr. Hintz $4,500; Mr. Jackson $4,500; Mr. Lupberger $4,500; Mr. Maulden $4,500; Mr. McInvale $4,500; Mr. Randall $4,500.

(4) 1994 reimbursements under the Executive Financial Counseling Program as follows: Mr. Bemis $2,725; Mr. Hintz $785; Mr. Jackson $1,175; Mr. Lupberger $2,623; Mr. Maulden $1,350; Mr. McInvale $645.

(5) 1994 payments for personal use under the Private Ownership Vehicle Plan as follows: Mr. Bemis $9,900; Mr. Blount $7,200; Mr. Hintz $10,800; Mr. Jackson $10,800; Mr. Lupberger $4,627; Mr. Maulden $9,720; Mr. McInvale $9,900; Mr. Randall $7,200.

(d) Restricted stock awarded under the Equity Ownership Plan is subject to performance based criteria. Restricted stock awards in 1994 are reported under the "Long-Term Incentive Plan Awards" table, and reference is made to this table for information on the aggregate number of restricted shares awarded during 1994 and the vesting schedule for such shares. At December 31, 1994, the number and value of the aggregate restricted stock holdings were as follows: Mr. Bemis: 12,750 shares, $278,907; Mr. Hintz: 17,568 shares, $384,300; Mr. Jackson: 18,000 shares, $393,750; Mr. Lupberger: 33,950 shares, $742,657; Mr. Maulden: 18,000 shares, $393,750; and Mr. McInvale: 12,750 shares, $278,907. Accumulated dividends are paid on restricted stock when vested. The value of stock for which restrictions were lifted in 1994, and the applicable portion of accumulated cash dividends, are reported in the LTIP Payouts column in the above table. The value of restricted stock awards as of December 31, 1994 are determined by multiplying the total number of shares awarded by the closing market price of Entergy Corporation common stock on the New York Stock Exchange Composite Transactions on December 31, 1994 ($21.875 per share).

Option Grants in 1994

The following table summarizes option grants during 1994 to the executive officers named in the Summary Compensation Table above. The absence, in the table below, of any named officer indicates that no options were granted to such officer.

AP&L, GSU, LP&L, MP&L, NOPSI, and System Entergy

	Individual Grants				Potential Realizable Value at Assumed Annual Rates of Stock Price Appreciation for Option Term(b)	
Name	Number of Securities Underlying Options Granted(a)	% of Total Options Granted to Employees in 1994	Exercise Price (per share)(a)	Expiration Date	5%	10%
Michael B. Bemis	2,500	3.7%	$37.00	01/27/04	$ 58,173	$ 147,421
Donald C. Hintz	5,000	7.4%	37.00	01/27/04	116,346	294,842
Jerry D. Jackson	5,000	7.4%	37.00	01/27/04	116,346	294,842
Edwin Lupberger	10,000	14.8%	37.00	01/27/04	232,691	589,685
Jerry L. Maulden	5,000	7.4%	37.00	01/27/04	116,346	294,842
Gerald D. McInvale	2,500	3.7%	37.00	01/27/04	58,173	147,421

(a) Options were granted on January 27, 1994, pursuant to the Equity Ownership Plan. All options granted on this date have an exercise price equal to the closing price of Entergy Corporation common stock on the New York Stock Exchange Composite Transactions on January 27, 1994. These options became exercisable on July 28, 1994.

(b) Calculation based on the stock option exercise price over a ten-year period assuming annual compounding. The columns present estimates of potential values based on simple mathematical assumptions. The actual value, if any, an executive officer may realize is dependent upon the market price on the date of option exercise.

Long-Term Incentive Plan Awards in 1994

AP&L, GSU, LP&L, MP&L, NOPSI, and System Energy

The following table summarizes awards of restricted shares of Entergy Corporation common stock under the Equity Ownership Plan in 1994 to the executive officers of these companies named in the Summary Compensation Table above. The absence, in the table below, of any named officer indicates that no restricted shares were awarded to such officer in 1994.

Name	Number of Shares	Performance Period Until Maturation or Payout	Estimated Future Payouts Under Non-Stock Price-Based Plans(a) (b)		
			Threshold	Target	Maximum
Michael B. Bemis	11,250	01/01/94-12/31/96	3,750	7,500	11,250
Donald C. Hintz	15,000	01/01/94-12/31/96	5,000	10,000	15,000
Jerry D. Jackson	15,000	01/01/94-12/31/96	5,000	10,000	15,000
Edwin Lupberger	25,200	01/01/94-12/31/96	8,400	16,800	25,200
Jerry L. Maulden	15,000	01/01/94-12/31/96	5,000	10,000	15,000
Gerald D. McInvale	11,250	01/01/94-12/31/96	3,750	7,500	11,250

(a) Restricted shares awarded will vest at the end of a three-year period, subject to the attainment of approved performance goals for the participants. Restrictions are lifted based upon the achievement of the cumulative result of these goals for the performance period. The value an executive officer may realize is dependent upon both the number of shares that vest and the future market price of Entergy Corporation common stock.

(b) The Threshold, Target and Maximum levels correspond to the achievement of 50%, 100%, and 150%, respectively, of Equity Ownership Plan goals. Achievement of a Threshold, Target or Maximum level would result in the award of the number of shares indicated in the respective column. Achievement of a level between these three specified levels would result in the award of a number of shares calculated by means of interpolation.

AP&L, GSU, LP&L, MP&L, NOPSI, and System Energy

Retirement Income Plan Table

Annual Covered Compensation	Years of Service				
	15	20	25	30	35
$100,000	$ 22,500	$ 30,000	$ 37,500	$ 45,000	$ 52,000
200,000	45,500	60,000	75,000	90,000	105,000
300,000	67,500	90,000	112,500	135,000	157,500
400,000	90,000	120,000	150,000	180,000	210,000
500,000	112,500	150,000	187,500	225,000	262,500
850,000	191,250	255,000	318,750	382,500	446,250

AP&L, GSU (non-bargaining unit employees), LP&L, MP&L, and System Energy each individually sponsors or participates in a Retirement Income Plan (a defined benefit plan) that provides a benefit for employees at retirement from the System based upon (1) generally all years of service beginning at age 21 through termination, with a forty-year maximum, times (2) 1.5% for each year of service, times (3) the final average compensation. Final average compensation is based on the highest 60 months of covered compensation in the last 120 months of service. The normal form of benefit for a single employee is a lifetime annuity and for a married employee is a 50% joint and survivor annuity. Other actuarially equivalent options are available to each retiree. Retirement benefits are not subject to any deduction for Social Security or other offset amounts. NOPSI is a participating employer in LP&L's Retirement Income Plan. System Energy is a participating employer in the Retirement Income Plan sponsored by Entergy Corporation. Prior to October 1, 1994, GSU sponsored a defined benefit pension plan for non-bargaining unit employees with different provisions from the other System Companies. However, effective October 1, 1994, GSU amended this plan for non-bargaining unit employees to be consistent with the other System companies. Bargaining unit employees for GSU are covered by the provisions of the pre-merger GSU defined benefit plan. The amount of the named executive officers' annual compensation covered by the plan as of December 31, 1994 is represented by the base salary column in the Summary Compensation Table of AP&L, GSU, LP&L, MP&L, NOPSI, and System Energy.

The maximum benefit under each Retirement Income Plan is limited by Sections 401 and 415 of the Internal Revenue Code; however, AP&L, GSU, LP&L, MP&L, NOPSI, and System Energy have elected to participate in the Pension Equalization Plan sponsored by Entergy Corporation. Under this plan, certain executives, including the named executive officers, would receive an amount equal to the benefit payable under the Retirement Income Plans, without regard to the limitations, less the amount actually payable under the Retirement Income Plans.

Each Retirement Income Plan (except GSU) was amended effective February 1, 1991 to provide a minimum accrued benefit as of that date to any employee who was vested as of that date. For purposes of calculating such minimum accrued benefit, each eligible employee was deemed to have had an additional five years of service and age as of that date. The additional years of age did not count toward eligibility for early retirement, but served only to reduce the early retirement discount factor for those employees who were at least age 50 as of that date. Effective January 1, 1995, the System companies Retirement Income Plans were amended to transfer assets and related liabilities to a single Entergy Corporation Retirement Plan for all non-bargaining unit employees.

The credited years of service under the Retirement Income Plan (without giving effect to the five additional years of service credited pursuant to the February 1, 1991 amendment as discussed above) as of December 31, 1994

for the following executive officers named in the Summary Compensation Table of AP&L, GSU, LP&L, MP&L, NOPSI, and System Energy were: Mr. Bemis 12, Mr. Blount 10, Mr. Maulden 29, and Mr. Randall 15.

The credited years of service under the respective Retirement Income Plans, as amended, as of December 31, 1994 for the following executive officers named in the Summary Compensation Table, as a result of entering into supplemental retirement agreements, were as follows: Mr. Hintz 23; Mr. Jackson 15; Mr. Lupberger 31; and Mr. McInvale 22.

In addition to the Retirement Income Plan discussed above, AP&L, LP&L, MP&L, NOPSI, and System Energy participate in the Supplemental Retirement Plan of Entergy Corporation and Subsidiaries (SRP) and the Post-Retirement Plan of Entergy Corporation and Subsidiaries (PRP). Participation is limited to one of these two plans and is at the invitation of AP&L, LP&L, MP&L, NOPSI, and System Energy. The participant may receive from the appropriate System company a monthly benefit payment not in excess of .025 (under the SRP) or .0333 (under the PRP) times the participant's average basic annual salary (as defined in the plans) for a maximum of 120 months. Mr. Hintz has entered into a SRP participation contract, and all of the other executive officers of AP&L, LP&L, MP&L, NOPSI, and System Energy named in the Summary Compensation Table (except for Mr. Blount and Mr. McInvale) have entered into PRP participation contracts.

System Executive Retirement Plan Table (1)

Annual Covered Compensation	Years of Service			
	15	20	25	30+
$ 200,000	$ 90,000	$100,000	$110,000	$120,000
300,000	135,000	150,000	165,000	180,000
400,000	180,000	200,000	220,000	240,000
500,000	225,000	250,000	275,000	300,000
600,000	270,000	300,000	330,000	360,000
700,000	315,000	350,000	385,000	420,000
1,000,000	450,000	500,000	550,000	600,000

(1) Benefits shown are based on a target replacement ratio of 50% based on the years of service and covered compensation shown. The benefits for 10, 15, and 20 or more years of service at the 45% and 55% replacement levels would decrease (in the case of 45%) or increase (in the case of 55%) by the following percentages: 3.0%, 4.5%, and 5.0%, respectively.

In 1993, Entergy Corporation adopted the System Executive Retirement Plan (SERP). AP&L, GSU, LP&L, MP&L, NOPSI, and System Energy are participating employers in the SERP. The SERP is an unfunded defined benefit plan offered at retirement to certain senior executives, which would currently include all the executive officers (except for Mr. Blount) named in the Summary Compensation Table of AP&L, GSU, LP&L, MP&L, NOPSI, and System Energy. Participating executives choose, at retirement, between the retirement benefits paid under provisions of the SERP or those payable under the executive retirement benefit plans discussed above. Covered pay under the SERP includes final annual base salary (see the Summary Compensation Table of AP&L, GSU, LP&L, MP&L, NOPSI, and System Energy for the base salary covered by the SERP as of December 31, 1994) plus the Target Incentive Award (i.e., a percentage of final annual base salary) for the participant in effect at retirement. Benefits paid under the SERP are calculated by multiplying the covered pay times target pay replacement ratios (45%, 50%, or 55%, dependent on job rating at retirement) that are attained, according to plan design, at 20 years of credited service. The target ratios are increased by 1% for each year of service over 20 years, up to a maximum of 30 years of service. In accordance with the SERP formula, the target ratios are reduced for each year of service below 20 years. The credited years of service under this plan are

identical to the years of service for named executive officers (other than Mr. Bemis, Mr. Jackson and Mr. McInvale) disclosed above in the "Pension Plan Tables-Retirement Income Plan Table" section. Mr. Bemis, Mr. Jackson and Mr. McInvale have 22 years, 21 years and 13 years, respectively, of credited service under this plan.

The normal form of benefit for a single employee is a lifetime annuity and for a married employee is a 50% joint and survivor annuity. All SERP payments are guaranteed for ten years. Other actuarially equivalent options are available to each retiree. SERP benefits are offset by any and all defined benefit plan payments from the company and from prior employers. SERP benefits are not subject to Social Security offsets.

Eligibility for and receipt of benefits under any of the executive plans described above are contingent upon several factors. The participant must agree that, without the specific consent of the System company for which such participant was last employed, he may take no employment after retirement with any entity that is in competition with, or similar in nature to, AP&L, GSU, LP&L, MP&L, NOPSI, and System Energy or any affiliate thereof. Eligibility for benefits is forfeitable for various reasons, including violation of an agreement with AP&L, GSU, LP&L, MP&L, NOPSI, and System Energy, resignation of employment, or termination for cause.

In addition to the non-bargaining unit employees Retirement Income Plan discussed above, GSU provides, among other benefits to officers, an Executive Income Security Plan for key managerial personnel. The plan provides participants with certain retirement, disability, termination, and survivors' benefits. To the extent that such benefits are not funded by the employee benefit plans of GSU or by vested benefits payable by the participants' former employers, GSU is obligated to make supplemental payments to participants or their survivors. The plan provides that upon the death or disability of a participant during his employment, he or his designated survivors will receive (i) during the first year following his death or disability an amount not to exceed his annual base salary, and (ii) thereafter for a number of years until the participant attains or would have attained age 65, but not less than nine years, an amount equal to one-half of the participant's annual base salary. The plan also provides supplemental retirement benefits for life for participants retiring after reaching age 65 equal to 1/2 of the participant's average final compensation rate, with 1/2 of such benefit upon the death of the participant being payable to a surviving spouse for life.

GSU amended and restated the plan effective March 1, 1991, to provide such benefits for life upon termination of employment of a participating officer or key managerial employee without cause (as defined in the plan) or if the participant separates from employment for good reason (as defined in the plan), with 1/2 of such benefits to be payable to a surviving spouse for life. Further, the plan was amended to provide medical benefits for a participant and his family when the participant separates from service. These medical benefits generally continue until the participant is eligible to receive medical benefits from a subsequent employer; but in the case of a participant who is over 50 at the time of separation and was participating in the plan on March 1, 1991, medical benefits continue for life. By virtue of the 1991 amendment and restatement, benefits for a participant cannot be modified once he becomes eligible to participate in the plan.

Compensation of Directors

AP&L, GSU, LP&L, MP&L, NOPSI, and System Energy currently have no non-employee directors, and each current director is not compensated for his responsibilities as director. However, for the period January 1, 1994 through May 5, 1994, AP&L, GSU, LP&L, MP&L, and NOPSI did have non-employee directors. These directors were paid an attendance fee of $1,000 for attendance at meetings of their respective Board of Directors, $1,000 (except for the chairman of such committee who was paid $1,500) for attendance at meetings of committees of the Board and $1,000 for participation, on behalf of their respective company, in any inspection trip or conference not held on the same day as a Board or committee meeting. All non-employee directors were also compensated on a quarterly basis in the form of fixed awards of Entergy Corporation common stock pursuant to the Stock Plan for Outside Directors (Directors Plan) and cash based on 1/2 the value of the stock awarded pursuant to the Directors Plan. This level of directors' compensation was set to enable Entergy System companies to attract and retain persons of outstanding competence to serve on the Boards of Directors. Directors were paid a portion of

their compensation in the form of Entergy Corporation's common stock in order to assure that directors would have a personal interest in the performance of the stock of Entergy Corporation. Non-employee directors were awarded 50 shares of Entergy Corporation common stock quarterly, which may have been authorized but unissued shares or shares acquired in the open market. Effective May 6, 1994, all non-employee directors of AP&L, GSU, LP&L, MP&L, NOPSI, and System Energy became advisory directors of the respective Company.

Retired non-employee directors of AP&L, LP&L, MP&L, and NOPSI with a minimum of five years of service on the respective Boards of Directors are paid $200 a month for a term corresponding to the number of years of service. Retired directors with over ten years of service receive a lifetime benefit of $200 a month. Years of service as an advisory director are included in calculating this benefit. System Energy has no retired non-employee directors.

Retired non-employee directors of GSU receive retirement benefits under a plan in which all directors who served continuously for a period of years will receive a percentage of their retainer fee in effect at the time of their retirement for life. The retirement benefit is 30 percent of the retainer fee for service of not less than five nor more than nine years, 40 percent for service of not less than ten nor more than fourteen years, and 50 percent for fifteen or more years of service. For those directors who retired prior to the retirement age, their benefits will be reduced. The plan also provides disability retirement and optional hospital and medical coverage if the director has served at least five years prior to the disability. The retired director pays one-third of the premium for such optional hospital and medical coverage and GSU pays the remaining two-thirds. Years of service as an advisory director are included in calculating these benefits.

Employment Contracts and Termination of Employment and Change-in-Control Arrangements

GSU

GSU established on January 18, 1991, an Executive Continuity Plan for elected and appointed officers providing for severance benefits equal to 2.99 times the officer's annual compensation upon termination of employment for reasons other than cause or upon a resignation of employment for good reason within two years after a change in control of GSU. Benefits are prorated if the officer is within three years of normal retirement age (65) at termination of employment. The plan further provides for continued participation in medical, dental and life insurance programs for three years following termination unless such benefits are available from a subsequent employer. The plan provides for outplacement assistance to aid a terminated officer in securing another position. Upon consummation of the Entergy/GSU merger on December 31, 1993, GSU made a one time contribution of $16,330,693 to a trust equivalent to the then present value of the maximum benefits which might be payable under the plan. As of December 31, 1994, the balance in the trust had been reduced to $8,102,203. If and to the extent outstanding benefits are not paid to the participants, the balance in the trust will be returned to GSU.

As a result of the Entergy/GSU merger, GSU is obligated to pay benefits under the Executive Income Security Plan to those persons who were participants at the time of the merger and who later terminated their employment under circumstances described in the plan. For additional description of the benefits under the Executive Income Security Plan, see the "Pension Plan Tables-System Executive Retirement Plan Table" section noted above.

Personnel Committee Interlocks and Insider Participation

The following persons served as members of the Personnel Committee of AP&L's, GSU's, LP&L's, MP&L's, and NOPSI's Board of Directors through May 5, 1994:

AP&L - John A. Cooper, Jr.*, Edwin Lupberger, Roy L. Murphy, Woodson D. Walker

GSU - Monroe J. Rathbone, Jr., M.D., Sam F. Segnar*, Bismark A. Steinhagen

LP&L - Tex. R. Kilpatrick*, Edwin Lupberger, Wm. Clifford Smith

MP&L - Norman B. Gillis, Robert E. Kennington, II*, Edwin Lupberger, Robert M. Williams, Jr.

NOPSI - Edwin Lupberger, Anne M. Milling, John B. Smallpage*

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* Denotes Chairman of the Personnel Committee

System Energy does not have a Personnel Committee of the Board of Directors. The compensation of System Energy's executive officers (with the exception of one officer) was set by the Personnel Committee of Entergy Corporation's Board of Directors for 1994. After May 5, 1994, the compensation of AP&L, GSU, LP&L, MP&L, and NOPSI executive officers was set by the Personnel Committee of Entergy Corporation's Board of Directors due to the elimination of the Personnel Committees of these companies. No officers or employees of such companies participated in deliberations concerning compensation during 1994. The Personnel Committee of Entergy Corporation's Board of Directors is set forth under the heading "Report of Personnel Committee on Executive Compensation" contained in the Proxy Statement of Entergy Corporation to be filed in connection with its Annual Meeting of Stockholders to be held May 26, 1995, and is incorporated herein by reference.

Mr. Lupberger is currently and was during 1994 an officer of AP&L, LP&L, MP&L, and NOPSI and also served as an executive officer of their subsidiary, System Fuels, from 1981 - 1990.

Item 12. Security Ownership of Certain Beneficial Owners and Management

Entergy Corporation owns 100% of the outstanding common stock of registrants AP&L, GSU, LP&L, MP&L, NOPSI, and System Energy. The information with respect to persons known by Entergy Corporation to be beneficial owners of more than 5% of Entergy Corporation's common stock is included under the heading "Voting Securities Outstanding" in the Proxy Statement of Entergy Corporation to be filed in connection with its Annual Meeting of Stockholders to be held May 26, 1995, which information is incorporated herein by reference. The registrants know of no contractual arrangements that may, at a subsequent date, result in a change in control of any of the registrants.

The directors, the executive officers named in the Summary Compensation Tables, and the directors and officers as a group for Entergy Corporation, AP&L, GSU, LP&L, MP&L, NOPSI, and System Energy, respectively, beneficially owned directly or indirectly the following cumulative preferred stock of a System company and common stock of Entergy Corporation:

	As of December 31, 1994			
	Preferred Stock		Entergy Corporation Common Stock	
	Amount and Nature of Beneficial Ownership(b)		Amount and Nature of Beneficial Ownership(b)	
Name	Sole Voting and Investment Power(c)	Other Beneficial Ownership	Sole Voting and Investment Power(c)	Other Beneficial Ownership (d)(e)(f)(g)
Entergy Corporation				
W. Frank Blount*	-	-	2,934	-
John A. Cooper, Jr.*	6,000 (a)	-	5,734	-
Lucie J. Fjeldstad*	-	-	1,984	-
Dr. Norman C. Francis*	-	-	500	-
Donald C. Hintz**	-	-	7,493	32,027
Kancaster Hodges, Jr.*	-	-	2,800	-
Jerry D. Jackson**	-	-	6,402	35,216
Robert v.d. Luft*	-	-	2,184	-
Edwin Lupberger**	-	-	8,706	73,687 (h)(i)
Jerry L. Maulden**	-	-	37,420	44,048
Gerald D. McInvale**	-	-	3,173	20,908
Adm. Kinnaird R. McKee*	-	-	2,900	-
Paul W. Murrill*	-	-	2,180	-
James R. Nichols*	-	-	3,315	-
Eugene H. Owen*	-	3,500 (a)	1,692	-
John N. Palmer, Sr.*	-	-	13,196	-
Robert D. Pugh*	-	-	5,300	10,000 (i)
H. Duke Shackelford*	-	-	8,750	4,950 (i)
Wm. Clifford Smith*	-	-	3,775	-
Bismark A. Steinhagen*	-	-	6,437	-
All directors and executive officers	6,000	3,500	135,419	266,320
AP&L				
Michael B. Bemis**	-	-	7,488	25,540
Donald C. Hintz**	-	-	7,493	32,027
Jerry D. Jackson**	-	-	6,402	35,216
R. Drake Keith***	-	-	2,891	13,260
Edwin Lupberger**	-	-	8,706	73,687 (h)(i)
Jerry L. Maulden**	-	-	37,420	44,048
All directors and executive officers	-	-	90,631	334,762

Name	As of December 31, 1994			
	Preferred Stock(a)		Entergy Corporation Common Stock	
	Amount and Nature of Beneficial Ownership(b)		Amount and Nature of Beneficial Ownership(b)	
	Sole Voting and Investment Power(c)	Other Beneficial Ownership	Sole Voting and Investment Power(c)	Other Beneficial Ownership (d)(e)(f)(g)
GSU				
Michael B. Bemis**	-	-	7,488	25,540
Frank F. Gallaher***	-	-	3,725	24,696 (j)
Donald C. Hintz**	-	-	7,493	32,027
Jerry D. Jackson**	-	-	6,402	35,216
Edwin Lupberger**	-	-	8,706	73,687 (h)(i)
Jerry L. Maulden**	-	-	37,420	44,048
All directors and executive officers	-	-	82,755	313,558
LP&L				
Michael B. Bemis**	-	-	7,488	25,540
John J. Cordaro***	-	-	1,747	9,877
Donald C. Hintz**	-	-	7,493	32,027
Jerry D. Jackson**	-	-	6,402	35,216
Edwin Lupberger**	-	-	8,706	73,687 (h)(i)
Jerry L. Maulden**	-	-	37,420	44,048
All directors and executive officers	-	-	86,348	335,037
MP&L				
Michael B. Bemis**	-	-	7,488	25,540
Donald C. Hintz*	-	-	7,493	32,027
Jerry D. Jackson**	-	-	6,402	35,216
Edwin Lupberger**	-	-	8,706	73,687 (h)(i)
Jerry L. Maulden**	-	-	37,420	44,048
Gerald D. McInvale**	-	-	3,173	20,908
Donald E. Meiners**	-	-	1,382	15,033 (j)
All directors and executive officers	-	-	83,958	330,524

Name	As of December 31, 1994			
	Preferred Stock(a)		Entergy Corporation Common Stock	
	Amount and Nature of Beneficial Ownership(b)		Amount and Nature of Beneficial Ownership(b)	
	Sole Voting and Investment Power(c)	Other Beneficial Ownership	Sole Voting and Investment Power(c)	Other Beneficial Ownership (d)(e)(f)(g)
NOPSI				
Michael B. Bemis**	-	-	7,488	25,540
John J. Cordaro***	-	-	1,747	9,877
Jerry D. Jackson**	-	-	6,402	35,216
Edwin Lupberger**	-	-	8,706	73,687 (h)(i)
Jerry L. Maulden**	-	-	37,420	44,048
Gerald D. McInvale**	-	-	3,173	20,908
All directors and executive officers	-	-	78,751	294,663
System Energy				
Joseph L. Blount**	-	-	834	2,287
Donald C. Hintz**	-	-	7,493	32,027
Jerry D. Jackson*	-	-	6,402	35,216
Edwin Lupberger**	-	-	8,706	73,687 (h)(i)
Jerry L. Maulden*	-	-	37,420	44,048
Gerald D. McInvale**	-	-	3,173	20,908
Lee W. Randall**	-	-	-	4,561
All directors and executive officers	-	-	64,028	212,734

* Director of the respective Company

** Named Executive Officer of the respective Company

*** Officer and Director of the respective Company

(a) Stock ownership amounts refer to 6,000 shares of AP&L's $0.01 Par Value ($25 liquidation value) Preferred Stock held by the John A. Cooper Trust, and 3,500 shares of AP&L's $0.01 Par Value ($25 liquidation value) Preferred Stock held by Eugene H. Owen. Mr. Cooper disclaims any personal interest in these shares.

(b) Based on information furnished by the respective individuals. The ownership amounts shown for each individual and for all directors and executive officers as a group do not exceed one percent of the outstanding securities of any class of security so owned.

(c) Includes all shares that the individual has the sole power to vote and dispose of, or to direct the voting and disposition of.

	As of December 31, 1994			
	Preferred Stock(a)		Entergy Corporation Common Stock	
	Amount and Nature of Beneficial Ownership(b)		Amount and Nature of Beneficial Ownership(b)	
Name	Sole Voting and Investment Power(c)	Other Beneficial Ownership	Sole Voting and Investment Power(c)	Other Beneficial Ownership (d)(e)(f)(g)
GSU				
Michael B. Bemis**	-	-	7,488	25,540
Frank F. Gallaher***	-	-	3,725	24,696 (j)
Donald C. Hintz**	-	-	7,493	32,027
Jerry D. Jackson**	-	-	6,402	35,216
Edwin Lupberger**	-	-	8,706	73,687 (h)(i)
Jerry L. Maulden**	-	-	37,420	44,048
All directors and executive officers	-	-	82,755	313,558
LP&L				
Michael B. Bemis**	-	-	7,488	25,540
John J. Cordaro***	-	-	1,747	9,877
Donald C. Hintz**	-	-	7,493	32,027
Jerry D. Jackson**	-	-	6,402	35,216
Edwin Lupberger**	-	-	8,706	73,687 (h)(i)
Jerry L. Maulden**	-	-	37,420	44,048
All directors and executive officers	-	-	86,348	335,037
MP&L				
Michael B. Bemis**	-	-	7,488	25,540
Donald C. Hintz*	-	-	7,493	32,027
Jerry D. Jackson**	-	-	6,402	35,216
Edwin Lupberger**	-	-	8,706	73,687 (h)(i)
Jerry L. Maulden**	-	-	37,420	44,048
Gerald D. McInvale**	-	-	3,173	20,908
Donald E. Meiners***	-	-	1,382	15,033 (j)
All directors and executive officers	-	-	83,958	330,524

	As of December 31, 1994			
	Preferred Stock(a)		Entergy Corporation Common Stock	
	Amount and Nature of Beneficial Ownership(b)		Amount and Nature of Beneficial Ownership(b)	
Name	Sole Voting and Investment Power(c)	Other Beneficial Ownership	Sole Voting and Investment Power(c)	Other Beneficial Ownership (d)(e)(f)(g)
NOPSI				
Michael B. Bemis**	-	-	7,488	25,540
John J. Cordaro***	-	-	1,747	9,877
Jerry D. Jackson**	-	-	6,402	35,216
Edwin Lupberger**	-	-	8,706	73,687 (h)(i)
Jerry L. Maulden**	-	-	37,420	44,048
Gerald D. McInvale**	-	-	3,173	20,908
All directors and executive officers	-	-	78,751	294,663
System Energy				
Joseph L. Blount**	-	-	834	2,287
Donald C. Hintz**	-	-	7,493	32,027
Jerry D. Jackson*	-	-	6,402	35,216
Edwin Lupberger**	-	-	8,706	73,687 (h)(i)
Jerry L. Maulden*	-	-	37,420	44,048
Gerald D. McInvale**	-	-	3,173	20,908
Lee W. Randall**	-	-	-	4,561
All directors and executive officers	-	-	64,028	212,734

* Director of the respective Company

** Named Executive Officer of the respective Company

*** Officer and Director of the respective Company

(a) Stock ownership amounts refer to 6,000 shares of AP&L's $0.01 Par Value ($25 liquidation value) Preferred Stock held by the John A. Cooper Trust, and 3,500 shares of AP&L's $0.01 Par Value ($25 liquidation value) Preferred Stock held by Eugene H. Owen. Mr. Cooper disclaims any personal interest in these shares.

(b) Based on information furnished by the respective individuals. The ownership amounts shown for each individual and for all directors and executive officers as a group do not exceed one percent of the outstanding securities of any class of security so owned.

(c) Includes all shares that the individual has the sole power to vote and dispose of, or to direct the voting and disposition of.

(d) Includes, for the named persons, shares of Entergy Corporation common stock held in the Employee Stock Ownership Plan of the registrants as follows: Michael B. Bemis, 714 shares; Joseph L. Blount, 753 shares; John J. Cordaro, 1,007 shares; Frank F. Gallaher, 941 shares; Donald C. Hintz, 753 shares; Jerry D. Jackson, 753 shares; R. Drake Keith, 753 shares; Edwin Lupberger, 825 shares; Jerry L. Maulden, 796 shares; Gerald D. McInvale, 110 shares; Donald E. Meiners, 553 shares; and Lee W. Randall, 791 shares.

(e) Includes, for the named persons, shares of Entergy Corporation common stock held in the System Savings Plan company account as follows: Michael B. Bemis, 4,576 shares; Joseph L. Blount, 1,534 shares; John J. Cordaro, 1,670 shares; Frank F. Gallaher, 3,455 shares; Donald C. Hintz, 1,206 shares; Jerry D. Jackson, 2,052 shares; R. Drake Keith, 3,833 shares; Edwin Lupberger, 6,088 shares; Jerry L. Maulden, 10,252 shares; Gerald D. McInvale 548 shares; Donald E. Meiners, 4,404 shares; and Lee W. Randall, 3,770 shares.

(f) Includes, for the named persons, unvested restricted shares of Entergy Corporation common stock held in the Equity Ownership Plan as follows: Michael B. Bemis, 12,750 shares; John J. Cordaro, 2,200 shares; Frank F. Gallaher, 14,800 shares; Donald C. Hintz, 17,568 shares; Jerry D. Jackson, 18,000 shares; R. Drake Keith, 1,500 shares; Edwin Lupberger, 33,950 shares; Jerry L. Maulden, 18,000 shares; Gerald D. McInvale, 12,750 shares; and Donald E. Meiners, 1,500 shares.

(g) Includes, for the named persons, shares of Entergy Corporation common stock in the form of unexercised stock options awarded pursuant to the Equity Ownership Plan as follows: Michael B. Bemis, 7,500 shares; John J. Cordaro 5,000 shares; Frank F. Gallaher, 5,000 shares; Donald C. Hintz, 12,500 shares; Jerry D. Jackson, 14,411 shares; R. Drake Keith, 7,174 shares; Edwin Lupberger, 28,824 shares; Jerry L. Maulden, 15,000 shares; Gerald D. McInvale, 7,500 shares; and Donald E. Meiners, 7,500 shares.

(h) Includes 1,500 shares of Entergy Corporation common stock held jointly between Edwin Lupberger and Ms. E. H. Lupberger.

(i) Includes, for the named persons, shares of Entergy Corporation common stock held by their spouses. The named persons disclaim any personal interest in these shares as follows: Edwin Lupberger, 2,500 shares; Robert D. Pugh, 10,000 shares; and H. Duke Shackleford, 4,950 shares.

(j) Includes, for the named persons, shares of Entergy Corporation common stock held jointly with their spouses as follows: Frank F. Gallaher, 500 shares; and Don E. Meiners, 1,076 shares.

Item 13. Certain Relationships and Related Transactions

Information called for by this item concerning the directors and officers of Entergy Corporation is set forth under the heading "Certain Transactions" in the Proxy Statement of Entergy Corporation to be filed in connection with its Annual Meeting of Stockholders to be held on May 26, 1995, which information is incorporated herein by reference.

See Item 11, "Executive Compensation - Personnel Committee Interlocks and Insider Participation" for information on certain transactions required to be reported under this item.

Other than as provided under applicable corporate laws, the System companies do not have policies whereby transactions involving executive officers and directors of the System are approved by a majority of disinterested directors. However, pursuant to the Entergy Corporation Code of Conduct, transactions involving a System company and its executive officers must have prior approval by the next higher reporting level of that individual, and transactions involving a System company and its directors must be reported to the secretary of the appropriate System company.

PART IV

Item 14. Exhibits, Financial Statement Schedules, and Reports on Form 8-K.

(a)1. Financial Statements and Independent Auditors' Reports for Entergy, AP&L, GSU, LP&L, MP&L, NOPSI, and System Energy are listed in the Index to Financial Statements (see pages 56 and 57)

(a)2. Financial Statement Schedules

Reports of Independent Accountants on Financial Statement Schedules (see pages 385 and 386)

Financial Statement Schedules are listed in the Index to Financial Statement Schedules (see page S-1)

(a)3. Exhibits

Exhibits for Entergy, AP&L, GSU, LP&L, MP&L, NOPSI, and System Energy are listed in the Exhibit Index (see page E-1). Each management contract or compensatory plan or arrangement required to be filed as an exhibit hereto is identified as such by footnote in the Exhibit Index.

(b) Reports on Form 8-K

Entergy and GSU

A current report on Form 8-K, dated October 21, 1994, was filed with the SEC on October 28, 1994, reporting information under Item 5 "Other Materially Important Events".

A current report on Form 8-K, dated December 14, 1994, was filed with the SEC on December 16, 1994, reporting information under Item 5 "Other Materially Important Events".

A current report on Form 8-K, dated December 21, 1994, was filed with the SEC on December 22, 1994, reporting information under Item 5 "Other Materially Important Events".

Entergy, GSU, LP&L and NOPSI

A current report on Form 8-K, dated December 9, 1994, was filed with the SEC on December 9, 1994, reporting information under Items 4 and 7.

Entergy and NOPSI

A current report on Form 8-K, dated December 9, 1994, was filed with the SEC on January 9, 1995, reporting information under Item 5 "Other Materially Important Events".

EXPERTS

All statements in Part I of this Annual Report on Form 10-K as to matters of law and legal conclusions, based on the belief or opinion of System Energy or any System operating company or otherwise, pertaining to the titles to properties, franchises and other operating rights of certain of the registrants filing this Annual Report on Form 10-K, and their subsidiaries, the regulations to which they are subject and any legal proceedings to which they are parties are made on the authority of Friday, Eldredge & Clark, 2000 First Commercial Building, 400 West Capitol, Little Rock, Arkansas, as to AP&L and as to Entergy Services in regards to flood litigation; Monroe & Lemann (A Professional Corporation), 201 St. Charles Avenue, Suite 3300, New Orleans, Louisiana, as to LP&L and NOPSI; and Wise Carter Child & Caraway, Professional Association, Heritage Building, Jackson, Mississippi, as to MP&L and System Energy.

The statements attributed to Clark, Thomas & Winters, a professional corporation, as to legal conclusions with respect to GSU's rate regulation in Texas under Item 1. "Rate Matters and Regulation - Rate Matters - Retail Rate Matters - GSU" and in Note 2 to Entergy Corporation and Subsidiaries Consolidated Financial Statements and GSU's Financial Statements, "Rate and Regulatory Matters," have been reviewed by such firm and are included herein upon the authority of such firm as experts.

The statements attributed to Sandlin Associates regarding the analysis of River Bend Construction costs of GSU under Item 1. "Rate Matters and Regulation - Rate Matters - Retail Rate Matters - GSU" and in Note 2 to Entergy Corporation and Subsidiaries Consolidated Financial Statements and GSU's Financial Statements, "Rate and Regulatory Matters," have been reviewed by such firm and are included herein upon the authority of such firm as experts.

ENTERGY CORPORATION

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. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

ENTERGY CORPORATION

By LEE W. RANDALL
Lee W. Randall, Vice President
and Chief Accounting Officer

Date: March 27, 1995

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signature of each of the undersigned shall be deemed to relate only to matters having reference to the above-named company and any subsidiaries thereof.

Signature	Title	Date
LEE W. RANDALL Lee W. Randall	Vice President, Chief Accounting Officer and Assistant Secretary (Principal Accounting Officer)	March 27, 1995

Edwin Lupberger (Chairman of the Board, Chief Executive Officer and Director; Principal Executive Officer); Gerald D. McInvale (Senior Vice President and Chief Financial Officer; Principal Financial Officer); W. Frank Blount, John A. Cooper, Jr., N. C. Francis, Lucie J. Fjeldstad, Kaneaster Hodges, Jr., Robert v.d. Luft, Kinnaird R. McKee, Paul W. Murrill, James R. Nichols, Eugene H. Owen, John N. Palmer, Robert D. Pugh, H. Duke Shackelford, Wm. Clifford Smith, and Bismark A. Steinhagen (Directors).

By: LEE W. RANDALL
(Lee W. Randall, Attorney-in-fact)

March 27, 1995

ARKANSAS POWER & LIGHT COMPANY

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. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

ARKANSAS POWER & LIGHT COMPANY

By LEE W. RANDALL
Lee W. Randall, Vice President,
Chief Accounting Officer, and
Assistant Secretary

Date: March 27, 1995

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signature of each of the undersigned shall be deemed to relate only to matters having reference to the above-named company and any subsidiaries thereof.

Signature	Title	Date
LEE W. RANDALL Lee W. Randall	Vice President, Chief Accounting Officer and Assistant Secretary (Principal Accounting Officer)	March 27, 1995

Edwin Lupberger (Chairman of the Board, Chief Executive Officer and Director; Principal Executive Officer); Gerald D. McInvale (Senior Vice President and Chief Financial Officer; Principal Financial Officer); Michael B. Bemis, Donald C. Hintz, Jerry D. Jackson, R. Drake Keith, and Jerry L. Maulden (Directors).

By: LEE W. RANDALL
(Lee W. Randall, Attorney-in-fact)

March 27, 1995

GULF STATES UTILITIES COMPANY

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. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

GULF STATES UTILITIES COMPANY

By LEE W. RANDALL
Lee W. Randall, Vice President,
Chief Accounting Officer and
Assistant Secretary

Date: March 27, 1995

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signature of each of the undersigned shall be deemed to relate only to matters having reference to the above-named company and any subsidiaries thereof.

Signature	Title	Date
LEE W. RANDALL Lee W. Randall	Vice President, Chief Accounting Officer and Assistant Secretary (Principal Accounting Officer)	March 27, 1995

Edwin Lupberger (Chairman of the Board, Chief Executive Officer and Director; Principal Executive Officer); Gerald D. McInvale (Senior Vice President and Chief Financial Officer; Principal Financial Officer); Michael B. Bemis, Frank F. Gallaher, Donald C. Hintz, Jerry D. Jackson, and Jerry L. Maulden (Directors).

By: LEE W. RANDALL
(Lee W. Randall, Attorney-in-fact)

March 27, 1995

LOUISIANA POWER & LIGHT COMPANY

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. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

LOUISIANA POWER & LIGHT COMPANY

By LEE W. RANDALL
Lee W. Randall, Vice President,
Chief Accounting Officer and
Assistant Secretary

Date: March 27, 1995

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signature of each of the undersigned shall be deemed to relate only to matters having reference to the above-named company and any subsidiaries thereof.

Signature	Title	Date
LEE W. RANDALL Lee W. Randall	Vice President, Chief Accounting Officer and Assistant Secretary (Principal Accounting Officer)	March 27, 1995

Edwin Lupberger (Chairman of the Board, Chief Executive Officer and Director; Principal Executive Officer); Gerald D. McInvale (Senior Vice President and Chief Financial Officer; Principal Financial Officer); Michael B. Bemis, John J. Cordaro, Donald C. Hintz, Jerry D. Jackson, and Jerry L. Maulden (Directors).

By: LEE W. RANDALL
(Lee W. Randall, Attorney-in-fact)

March 27, 1995

MISSISSIPPI POWER & LIGHT COMPANY

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. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

MISSISSIPPI POWER & LIGHT COMPANY

By LEE W. RANDALL
Lee W. Randall, Vice President,
Chief Accounting Officer and
Assistant Secretary

Date: March 27, 1995

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signature of each of the undersigned shall be deemed to relate only to matters having reference to the above-named company and any subsidiaries thereof.

Signature	Title	Date
LEE W. RANDALL Lee W. Randall	Vice President, Chief Accounting Officer and Assistant Secretary (Principal Accounting Officer)	March 27, 1995

Edwin Lupberger (Chairman of the Board, Chief Executive Officer and Director; Principal Executive Officer); Gerald D. McInvale (Senior Vice President and Chief Financial Officer; Principal Financial Officer); Michael B. Bemis, Donald C. Hintz, Jerry D. Jackson, Jerry L. Maulden, and Donald E. Meiners (Directors).

By: LEE W. RANDALL
(Lee W. Randall, Attorney-in-fact)

March 27, 1995

NEW ORLEANS PUBLIC SERVICE INC.

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. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

NEW ORLEANS PUBLIC SERVICE INC.

By LEE W. RANDALL
Lee W. Randall, Vice President,
Chief Accounting Officer and
Assiatant Secretary

Date: March 27, 1995

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signature of each of the undersigned shall be deemed to relate only to matters having reference to the above-named company and any subsidiaries thereof.

Signature	Title	Date
LEE W. RANDALL Lee W. Randall	Vice President, Chief Accounting Officer and Assistant Secretary (Principal Accounting Officer)	March 27, 1995

Edwin Lupberger (Chairman of the Board, Chief Executive Officer and Director; Principal Executive Officer); Gerald D. McInvale (Senior Vice President and Chief Financial Officer; Principal Financial Officer); John J. Cordaro, Jerry D. Jackson, and Jerry L. Maulden (Directors).

By: LEE W. RANDALL
(Lee W. Randall, Attorney-in-fact)

March 27, 1995

SYSTEM ENERGY RESOURCES, INC.

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. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

SYSTEM ENERGY RESOURCES, INC.

By LEE W. RANDALL
Lee W. Randall, Vice President
and Chief Accounting Officer

Date: March 27, 1995

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signature of each of the undersigned shall be deemed to relate only to matters having reference to the above-named company and any subsidiaries thereof

Signature	Title	Date
LEE W. RANDALL Lee W. Randall	Vice President and Chief Accounting Officer (Principal Accounting Officer)	March 27, 1995

Donald C. Hintz (President, Chief Executive Officer and Director; Principal Executive Officer); Gerald D. McInvale (Senior Vice President and Chief Financial Officer; Principal Financial Officer); Edwin Lupberger (Chairman of the Board), Donald C. Hintz, Jerry D. Jackson, and Jerry L. Maulden (Directors).

By: LEE W. RANDALL
(Lee W. Randall, Attorney-in-fact)

March 27, 1995

EXHIBIT 23(a)

CONSENT OF INDEPENDENT ACCOUNTANTS

We consent to the incorporation by reference in Post-Effective Amendment Nos. 2, 3, 4A, and 5A on Form S-8 and the related Prospectuses to registration statement of Entergy Corporation on Form S-4 (File Number 33-54298), of our reports dated February 21, 1995, except for the last paragraph of the section of Note 2 to the consolidated financial statements subtitled "Filings with the PUCT and Texas Cities" as to which the date is March 20, 1995, on our audit of the consolidated financial statements and financial statement schedules of Entergy Corporation as of and for the year ended December 31, 1994, which reports include explanatory paragraphs related to rate-related contingencies and legal proceedings and are included in this Annual Report on Form 10-K.

We consent to the incorporation by reference in the registration statements and the related Prospectuses of Arkansas Power & Light Company on Form S-3 (File Number 33-36149, 33-48356 and 33-50289) of our reports dated February 21, 1995 on our audit of the financial statements and financial statement schedules of Arkansas Power & Light Company as of and for the year ended December 31, 1994 which are included in this Annual Report on Form 10-K.

We consent to the incorporation by reference in registration statements and the related Prospectuses of Gulf States Utilities Company on Form S-3 (File Numbers 33-49739 and 33-51181) and Form S-8 (File Numbers 2-76551 and 2-98011) of our reports dated February 21, 1995, except for the last paragraph of the section of Note 2 to the financial statements subtitled "Filings with the PUCT and Texas Cities" as to which the date is March 20, 1995, on our audits of the financial statements and financial statement schedules of Gulf States Utilities Company as of December 31, 1994 and 1993 and for the three years ended December 31, 1994, which reports include explanatory paragraphs related to rate-related contingencies, legal proceedings and changes in accounting for income taxes, postretirement benefits, unbilled revenue and power plant materials and supplies and are included in this Annual Report on Form 10-K.

We consent to the incorporation by reference in the registration statements and the related Prospectuses of Louisiana Power & Light Company on Form S-3 (File Numbers 33-46085, 33-39221 and 33-50937) of our reports dated February 21, 1995 on our audit of the financial statements and financial statement schedules of Louisiana Power & Light Company as of and for the year ended December 31, 1994 which are included in this Annual Report on Form 10-K.

We consent to the incorporation by reference in the registration statements and the related Prospectuses of Mississippi Power & Light Company on Form S-3 (File Numbers 33-53004, 33-55826 and 33-50507) of our reports dated February 21, 1995 on our audit of the financial statements and financial statement schedules of Mississippi Power & Light Company as of and for the year ended December 31, 1994 which are included in this Annual Report on Form 10-K.

We consent to the incorporation by reference in the registration statement and the related Prospectus of New Orleans Public Service Inc. on Form S-3 (File Number 33-57926) of our reports dated February 21, 1995 on our audit of the financial statements and financial statement schedules of New Orleans Public Service Inc. as of and for the year ended December 31, 1994 which are included in this Annual Report on Form 10-K.

We consent to the incorporation by reference in the registration statement and the related Prospectus of System Energy Resources, Inc. on Form S-3 (File Number 33-47662) of our reports dated February 21, 1995 on our audit of the financial statements and financial statement schedules of System Energy Resources, Inc. as of and for the year ended December 31, 1994 which are included in this Annual Report on Form 10-K.

COOPERS & LYBRAND L.L.P.
New Orleans, Louisiana
March 24, 1995

INDEPENDENT AUDITORS' CONSENT

We consent to the incorporation by reference in Post-Effective Amendment Nos. 2, 3, 4A, and 5A on Form S-8 to Registration Statement No. 33-54298 of Entergy Corporation on Form S-4, and the related Prospectuses, of our reports dated February 11, 1994 (which express an unqualified opinion and include explanatory paragraphs as to uncertainties because of certain regulatory and litigation matters), appearing in this Annual Report on Form 10-K of Entergy Corporation.

We also consent to the incorporation by reference in Registration Statements Nos. 33-36149, 33-48356 and 33-50289 of Arkansas Power & Light Company on Form S-3, and the related Prospectuses, of our reports dated February 11, 1994, appearing in this Annual Report on Form 10-K of Arkansas Power & Light Company.

We also consent to the incorporation by reference in Registration Statements Nos. 33-46085, 33-39221 and 33-50937 of Louisiana Power & Light Company on Form S-3, and the related Prospectuses, of our reports dated February 11, 1994, appearing in this Annual Report on Form 10-K of Louisiana Power & Light Company.

We also consent to the incorporation by reference in Registration Statements Nos. 33-53001, 33-55826 and 33-50507 of Mississippi Power & Light Company on Form S-3, and the related Prospectuses, of our reports dated February 11, 1994, appearing in this Annual Report on Form 10-K of Mississippi Power & Light Company.

We also consent to the incorporation by reference in Registration Statement No. 33-57926 of New Orleans Public Service Inc. on Form S-3, and the related Prospectus, of our reports dated February 11, 1994, appearing in this Annual Report on Form 10-K of New Orleans Public Service Inc.

We also consent to the incorporation by reference in Registration Statement No. 33-47662 of System Energy Resources, Inc. on Form S-3, and the related Prospectus, of our reports dated February 11, 1994 (November 30, 1994 as to Note 2, "Rate and Regulatory Matters - FERC Settlement"), appearing in this Annual Report on Form 10-K of System Energy Resources, Inc.

DELOITTE & TOUCHE LLP
New Orleans, Louisiana
March 27, 1995

CONSENT OF EXPERTS

We consent to the reference to our firm under the heading "Experts" in this Annual Report on Form 10-K. We further consent to the incorporation by reference of such reference to our firm into Arkansas Power & Light Company's ("AP&L") Registration Statements (Form S-3, File Nos. 33-36149, 33-48356 and 33-50289) and related Prospectuses, pertaining to AP&L's First Mortgage Bonds and Preferred Stock.

Very truly yours,

FRIDAY, ELDREDGE & CLARK

Date: March 27, 1995

CONSENT

We consent to the reference to our firm under the heading "Experts", and to the inclusion in this Annual Report on Form 10-K of Gulf States Utilities Company ("GSU") of the statements of legal conclusions attributed to us herein (the Statements of Legal Conclusions) under Part I, Item 1, Business - "Rate Matters and Regulation" and in the discussion of Texas jurisdictional matters set forth in Note 2 to GSU's Financial Statements and Note 2 to Entergy Corporation and Subsidiaries Consolidated Financial Statements appearing as Item 8, of Part II of this Form 10-K, which Statements of Legal Conclusions have been prepared or reviewed by us (Clark, Thomas & Winters, a Professional Corporation). We also consent to the incorporation by reference in the registration statements of GSU on Form S-3 and Form S-8 (File Numbers 2-76551, 2-98011, 33-49739, and 33-51181) of such reference and Statements of Legal Conclusions.]

CLARK, THOMAS & WINTERS
A Professional Corporation

Austin, Texas
March 27, 1995

CONSENT

We consent to the reference to our firm under the heading "Experts" and to the inclusion in this Annual Report on Form 10-K of Gulf States Utilities Company ("GSU") of the statements (Statements) regarding the analysis by our Firm of River Bend construction costs which are made herein under Part I, Item 1. Business - "Rate Matters and Regulation" and in the discussion of Texas jurisdictional matters set forth in Note 2 to GSU's Financial Statements and Note 2 to Entergy Corporation and Subsidiaries' Consolidated Financial Statements appearing as Item 8. of Part II of this Form 10-K, which Statements have been prepared or reviewed by us (Sandlin Associates). We also consent to the incorporation by reference in the registration statements of GSU on Form S-3 and Form S-8 (File Numbers 2-76551, 2-98011, 33-49739 and 33-51181) of such reference and Statements.

SANDLIN ASSOCIATES
Management Consultants

Pasco, Washington
March 27, 1995

EXHIBIT 23(f)

CONSENT OF EXPERTS

We consent to the reference to our firm under the heading "Experts" in this Annual Report on Form 10-K. We further consent to the incorporation by reference of such reference to our firm into Louisiana Power & Light Company's ("LP&L") Registration Statements (Form S-3, File Nos. 33-46085, 33-39221 and 33-50937) and the related Prospectuses, pertaining to LP&L's First Mortgage Bonds and Preferred Stock, and into New Orleans Public Service Inc.'s ("NOPSI") Registration Statement (Form S-3, File No. 33-57926) and the related Prospectus pertaining to NOPSI's General and Refunding Mortgage Bonds.

Very truly yours,

MONROE & LEMANN

Date: March 27, 1995

EXHIBIT 23(g)

CONSENT OF EXPERTS

We consent to the reference to our firm under the heading "Experts" in this Annual Report on Form 10-K. We further consent to the incorporation by reference of such reference to our firm into System Energy Resources, Inc.'s (System Energy) Registration Statement on Form S-3 (File No. 33-47662) and the related prospectus pertaining to System Energy's First Mortgage Bonds, and into Mississippi Power & Light Company's ("MP&L") Registration Statements on Form S-3 (File Nos. 33-53004, 33-55826 and 33-50501) and the related prospectuses pertaining to MP&L's Preferred Stock and General and Refunding Mortgage Bonds.

Very truly yours,

WISE CARTER CHILD & CARAWAY
Professional Association

By ROBERT B. MCGEHEE
Robert B. McGehee

Date: March 27, 1995

REPORT OF INDEPENDENT ACCOUNTANTS ON FINANCIAL STATEMENT SCHEDULES

To the Shareholders and the Board of Directors
of Entergy Corporation

We have audited the consolidated financial statements of Entergy Corporation and Subsidiaries and the financial statements of Arkansas Power & Light Company, Louisiana Power & Light Company, Mississippi Power & Light Company, New Orleans Public Service Inc., and System Energy Resources, Inc. as of and for the year ended December 31, 1994, and the financial statements of Gulf States Utilities Company as of December 31, 1994 and 1993, and for each of the three years in the period ended December 31, 1994, and have issued our reports included elsewhere in this Form 10-K, thereon dated February 21, 1995, except for the last paragraph of the section of the Entergy Corporation and Gulf States Utilities Company Note 2 subtitled "Filings with the PUCT and Texas Cities", as to which the date is March 20, 1995, which report as to Entergy Corporation and Gulf States Utilities Company include explanatory paragraphs related to rate-related contingencies and legal proceedings, and which report as to Gulf States Utilities Company includes an explanatory paragraph related to changes in accounting for income taxes, postretirement benefits, unbilled revenue and power plant materials and supplies. In connection with our audits of such financial statements, we have also audited the related financial statement schedules included in Item 14(a)2 of this Form 10-K.

In our opinion the financial statement schedules referred to above, when considered in relation to the basic financial statements taken as a whole, present fairly in all material respects the information required to be included therein.

COOPERS & LYBRAND L.L.P.
New Orleans, Louisiana
February 21, 1995, except for the last paragraph
of "Filings with the PUCT and Texas Cities" in
Note 2, as to which the date is March 20, 1995

INDEPENDENT AUDITORS' REPORT ON FINANCIAL STATEMENT SCHEDULES

To the Shareholders and the Board of Directors
of Entergy Corporation

We have audited the consolidated financial statements of Entergy Corporation and subsidiaries and the financial statements of Arkansas Power & Light Company, Louisiana Power & Light Company, Mississippi Power & Light Company, New Orleans Public Service Inc., and System Energy Resources, Inc. as of December 31, 1993, and for each of the two years in the period ended December 31, 1993, and have issued our reports thereon dated February 11, 1994, which report as to Entergy Corporation includes explanatory paragraphs as to uncertainties because of certain regulatory and litigation matters, and which report as to System Energy Resources, Inc. is dated November 30, 1994 as to Note 2, "Rate and Regulatory Matters - FERC Settlement"; such reports are included elsewhere in this Form 10-K. Our audits also included the 1993 and 1992 financial statement schedules of these companies, listed in Item 14(a)2. These financial statement schedules are the responsibility of the companies' managements. Our responsibility is to express an opinion based on our audits. We did not audit the financial statements of Gulf States Utilities Company (a consolidated subsidiary of Entergy Corporation acquired on December 31, 1993), which statements reflect total assets constituting 31% of consolidated total assets at December 31, 1993. Those statements were audited by other auditors whose report (which included explanatory paragraphs regarding uncertainties because of certain regulatory and litigation matters) has been furnished to us, and our opinion, insofar as it relates to the amounts included for Gulf States Utilities Company, is based solely on the report of such other auditors. In our opinion, based on our audits and the report of the other auditors, such financial statement schedules, when considered in relation to the basic financial statements taken as a whole, present fairly in all material respects the information set forth therein.

DELOITTE & TOUCHE LLP
New Orleans, Louisiana
February 11, 1994

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INDEX TO FINANCIAL STATEMENT SCHEDULES

Schedule		Page
I	Financial Statements of Entergy Corporation:	
	Balance Sheets, December 31, 1994 and 1993	S-2
	Statements of Cash Flows - For the Years Ended December 31, 1994, 1993 and 1992	S-3
	Statements of Income - For the Years Ended December 31, 1994, 1993 and 1992	S-4
	Statements of Retained Earnings and Paid-In Capital - For the Years Ended December 31, 1994, 1993 and 1992	S-5
II	Valuation and Qualifying Accounts 1994, 1993 and 1992:	
	Entergy Corporation and Subsidiaries	S-6
	Arkansas Power & Light Company	S-7
	Gulf States Utilities Company	S-8
	Louisiana Power & Light Company	S-9
	Mississippi Power & Light Company	S-10
	New Orleans Public Service Inc.	S-11

Schedules other than those listed above are omitted because they are not required, not applicable or the required information is shown in the financial statements or notes thereto.

Columns have been omitted from schedules filed because the information is not applicable.

ENTERGY CORPORATION

SCHEDULE I - FINANCIAL STATEMENTS OF ENTERGY CORPORATION
BALANCE SHEETS

	December 31,	
	1994	1993
	(In Thousands)	
ASSETS		
Construction work in progress	-	$22,861
Investment in Wholly-owned Subsidiaries	$6,110,504	6,449,165
Current Assets:		
Cash equivalents:		
Temporary cash investments - at cost, which approximates market:		
Associated companies	83,339	100,401
Other	169,369	52,150
Total cash equivalents	252,708	152,551
Accounts receivable:		
Associated companies	10,413	3,086
Other	375	2,467
Interest receivable	923	1,073
Other	6,901	1,166
Total	271,320	160,343
Deferred Debits	55,185	93,479
TOTAL	$6,437,009	$6,725,848
CAPITALIZATION AND LIABILITIES		
Capitalization:		
Common stock, $.01 par value in 1994 and 1993: authorized 500,000,000 shares; issued and outstanding 230,017,485 shares in 1994 and 231,219,737 shares in 1993	$2,300	$2,312
Paid-in capital	4,202,134	4,223,682
Retained earnings	2,223,739	2,310,082
Less - treasury stock (2,608,908 shares in 1994)	77,378	-
Total common shareholders' equity	6,350,795	6,536,076
Current Liabilities:		
Notes payable	-	43,000
Accounts payable:		
Associated companies	4,578	7,556
Other	1,102	10,069
Other current liabilities	5,021	1,849
Total	10,701	62,474
Deferred Credits and Noncurrent Liabilities	75,513	127,298
Total	$6,437,009	$6,725,848

See Entergy Corporation and Subsidiaries Notes to Consolidated Financial Statements in Part II, Item 8.

ENTERGY CORPORATION

SCHEDULE I - FINANCIAL STATEMENTS OF ENTERGY CORPORATION
STATEMENTS OF CASH FLOWS

	For the Years Ended December 31,		
	1994	1993	1992
		(In Thousands)	
Operating Activities:			
Net income	$341,841	$551,930	$437,637
Noncash items included in net income:			
Equity in earnings of subsidiaries	(369,702)	(557,681)	(454,947)
Deferred income taxes	7,007	3,771	3,146
Depreciation	959		
Changes in working capital:			
Receivables	(5,085)	(1,082)	2,875
Payables	(11,945)	1,367	(26,241)
Other working capital accounts	(2,563)	531	16,034
Common stock dividends received from subsidiaries	763,400	686,700	487,854
Other	(12,136)	(20,938)	(15,012)
Net cash flow provided by operating activities	711,776	664,598	451,346
Investing Activities:			
Merger with GSU - cash paid	-	(250,000)	-
Investment in subsidiaries	(49,892)	(86,221)	(79,228)
Capital expenditures	(3,178)	(22,861)	-
Decrease in other temporary investments	-	17,012	114,651
Proceeds received from the sale of property	26,000	-	-
Advance to subsidiary	(11,840)	(24,642)	(12,005)
Net cash flow provided by (used in) investing activities	(38,910)	(366,712)	23,418
Financing Activities:			
Changes in short-term borrowings	(43,000)	43,000	-
Common stock dividends paid	(410,223)	(287,483)	(256,117)
Retirement of common stock	(119,486)	(20,558)	(105,673)
Net cash flow used in financing activities	(572,709)	(265,041)	(361,790)
Net increase in cash and cash equivalents	100,157	32,845	112,974
Cash and cash equivalents at beginning of period	152,551	119,706	6,732
Cash and cash equivalents at end of period	$252,708	$152,551	$119,706
SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION			
Noncash investing and financing activities:			
Merger with GSU-Common stock issued	-	$2,031,101	-

See Entergy Corporation and Subsidiaries Notes to Consolidated Financial Statements in Part II, Item 8.

ENTERGY CORPORATION
SCHEDULE I-FINANCIAL STATEMENTS OF ENTERGY CORPORATION
STATEMENTS OF INCOME

	For the Years Ended December 31,		
	1994	1993	1992
		(In Thousands)	
Income:			
Equity in income of subsidiaries	$369,701	$557,681	$454,947
Interest on temporary investments	25,496	18,520	20,011
Total	395,197	576,201	474,958
Expenses and Other Deductions:			
Administrative and general expenses	57,846	25,129	32,412
Income taxes (credit)	(6,350)	3,587	4,734
Taxes other than income (credit)	465	(696)	167
Interest (credit)	1,395	(3,749)	8
Total	53,356	24,271	37,321
Net Income	$341,841	$551,930	$437,637

See Entergy Corporation and Subsidiaries Notes to consolidated financial Statements in Part II, Item 8.

ENTERGY CORPORATION

SCHEDULE I - FINANCIAL STATEMENTS OF ENTERGY CORPORATION
STATEMENTS OF RETAINED EARNINGS AND PAID-IN CAPITAL

	For the Years Ended December 31,		
	1994	1993	1992
		(In Thousands)	
Retained Earnings, January 1	$2,310,082	$2,062,188	$1,943,298
Add:			
Net income	341,841	551,930	437,637
Total	2,651,923	2,614,118	2,380,935
Deduct:			
Dividends declared on common stock	411,806	288,342	255,479
Common stock retirements	13,940	13,906	59,187
Capital stock and other expenses	2,438	1,788	4,081
Total	428,184	304,036	318,747
Retained Earnings, December 31	$2,223,739	$2,310,082	$2,062,188
Paid-in Capital, January 1	$4,223,682	$1,327,589	$1,357,883
Add:			
Gain (loss) on reacquisition of subsidiaries' preferred stock	(23)	(20)	(1,323)
Issuance of 56,695,724 shares of common stock in the merger with GSU	-	2,027,325	-
Issuance of 174,552,011 shares of common stock at $.01 par value net of the retirement of 174,552,011 shares of common stock at $5.00 par value	-	871,015	-
Total	4,223,659	4,225,909	1,356,560
Deduct:			
Common stock retirements	22,468	4,389	28,127
Capital stock discounts and other expenses	(943)	(2,162)	844
Total	21,525	2,227	28,971
Paid-in Capital, December 31	$4,202,134	$4,223,682	$1,327,589

See Entergy Corporation and Subsidiaries Notes to Consolidated Financial Statements in Part II, Item 8.

ENTERGY CORPORATION AND SUBSIDIARIES

SCHEDULE II - VALUATION AND QUALIFYING ACCOUNTS
Years Ended December 31, 1994, 1993, and 1992
(In Thousands)

Column A	Column B	Column C		Column D	Column E	Column F
		Additions		Other Changes		
Description	Balance at Beginning of Period	Charged to Income	Charged to Other Accounts (Note 1)	Deductions from Provisions (Note 2)	Acquistion of GSU	Baiance at End of Period
Year ended December 31, 1994						
Accumulated Provisions Deducted from Assets--						
Doubtful Accounts	$8,808	$8,266	-	$10,334	-	$6,740
Accumulated Provisions Not Deducted from Assets:						
Property insurance	$34,546	$25,592	-	$27,267	-	$32,871
Injuries and damages (Note 3)	23,096	10,993	-	12,023	-	22,066
Environmental	26,753	21,292	-	5,306	-	42,739
Total	$84,395	$57,877	-	$44,596	-	$97,676
Year ended December 31, 1993						
Accumulated Provisions Deducted from Assets--						
Doubtful Accounts	$6,193	$8,565	-	$8,333	$2,383	$8,808
Accumulated Provisions Not Deducted from Assets						
Property insurance	$25,177	$5,714	-	$7,217	$10,872	$34,546
Injuries and damages (Note 3)	15,978	11,702	-	14,053	9,469	23,096
Environmental	8,006	1,672	-	1,076	18,151	26,753
Total	$49,161	$19,088	-	$22,346	$38,492	$84,395
Year ended December 31, 1992						
Accumulated Provisions Deducted from Assets--						
Doubtful Accounts	$8,125	$3,654	-	$5,586	-	$6,193
Accumulated Provisions Not Deducted from Assets:						
Property insurance	$35,056	$10,820	-	$20,699	-	$25,177
Injuries and damages (Note 3)	14,614	11,053	20	9,709	-	15,978
Environmental	8,835	853	-	1,682	-	8,006
Total	$58,505	$22,726	$20	$32,090	-	$49,161

Notes:

(1) Charged to clearing and other accounts.

(2) Deductions from provisions represent losses or expenses for which the respective provisions were created. In the case of the provision for doubtful accounts, such deductions are reduced by recoveries of amounts previously written off.

(3) Injuries and damages provision is provided to absorb all current expenses as appropriate and for the estimated cost of settling claims for injuries and damages.

ARKANSAS POWER & LIGHT COMPANY

SCHEDULE II - VALUATION AND QUALIFYING ACCOUNTS
Years Ended December 31, 1994, 1993, and 1992
(In Thousands)

Column A	Column B	Column C		Column D	Column E
		Additions		Other Changes	
Description	Balance at Beginning of Period	Charged to Income	Charged to Other Accounts	Deductions from Provisions (Note 1)	Balance at End of Period
Year ended December 31, 1994					
Accumulated Provisions Deducted from Assets--					
Doubtful Accounts	$2,050	$1,967	-	$2,067	$1,950
Accumulated Provisions Not Deducted from Assets:					
Property insurance	$2,821	$18,782	-	$19,637	$1,916
Injuries and damages (Note 2)	3,259	1,316	-	1,915	2,660
Environmental	6,825	1,510	-	2,985	5,350
Total	$12,905	$21,608	-	$24,587	$9,926
Year ended December 31, 1993					
Accumulated Provisions Deducted from Assets--					
Doubtful Accounts	$1,613	$3,439	-	$3,002	$2,050
Accumulated Provisions Not Deducted from Assets:					
Property insurance	$5,182	$1,952	-	$4,313	$2,821
Injuries and damages (Note 2)	5,851	4,070	-	6,662	3,259
Environmental	6,766	1,122	-	1,063	6,825
Total	$17,799	$7,144	-	$12,038	$12,905
Year ended December 31, 1992					
Accumulated Provisions Deducted from Assets--					
Doubtful Accounts	$3,430	$(3)	-	$1,814	$1,613
Accumulated Provisions Not Deducted from Assets:					
Property insurance	$7,827	$4,000	-	$6,645	$5,182
Injuries and damages (Note 2)	4,254	7,086	-	5,489	5,851
Environmental	7,595	853	-	1,682	6,766
Total	$19,676	$11,939	-	$13,816	$17,799

Notes:

(1) Deductions from provisions represent losses or expenses for which the respective provisions were created. In the case of the provision for doubtful accounts, such deductions are reduced by recoveries of amounts previously written off.

(2) Injuries and damages provision is provided to absorb all current expenses as appropriate and for the estimated cost of settling claims for injuries and damages.

GULF STATES UTILITIES COMPANY

SCHEDULE II - VALUATION AND QUALIFYING ACCOUNTS
Years Ended December 31, 1994, 1993 and 1992
(In Thousands)

Column A	Column B	Column C		Column D	Column E
		Additions		Other Changes	
Description	Balance at Beginning of Period	Charged to Income	Charged to Other Accounts (Note 1)	Deductions from Provisions (Note 2)	Balance at End of Period
Year ended December 31, 1994					
Accumulated Provisions Deducted from Assets--					
Doubtful Accounts	$2,383	$701	-	$2,369	$715
Accumulated Provisions Not Deducted from Assets--					
Property insurance	$10,872	$2,170	-	$2,591	$10,451
Injuries and damages (Note 3)	9,469	2,970	-	5,517	6,922
Environmental	18,151	2,589	-	426	20,314
Total	$38,492	$7,729	-	$8,534	$37,687
Year ended December 31, 1993					
Accumulated Provisions Deducted from Assets--					
Doubtful Accounts	$2,953	$929	-	$1,499	$2,383
Accumulated Provisions Not Deducted from Assets--					
Property insurance	$9,397	$1,302	-	($173)	$10,872
Injuries and damages (Note 3)	6,594	11,511	-	8,636	9,469
Environmental	19,328	3	-	1,180	18,151
Total	$35,319	$12,816	-	$9,643	$38,492
Year ended December 31, 1992					
Accumulated Provisions Deducted from Assets--					
Doubtful Accounts	$2,796	$2,271	-	$2,114	$2,953
Accumulated Provisions Not Deducted from Assets--					
Property insurance	$10,975	($1,578)	-	$0	$9,397
Injuries and damages (Note 3)	5,120	3,367	-	1,893	6,594
Environmental	16,184	4,618	-	1,474	19,328
Total	$32,279	$6,407	-	$3,367	$35,319

Notes:

(1) Charged to clearing and other accounts.

(2) Deductions from provisions represent losses or expenses for which the respective provisions were created. In the case of the provision for doubtful accounts, such deductions are reduced by recoveries of amounts previously written off.

(3) Injuries and damages provision is provided to absorb all current expenses as appropriate and for the estimated cost of settling claims for injuries and damages.

LOUISIANA POWER & LIGHT COMPANY

SCHEDULE II - VALUATION AND QUALIFYING ACCOUNTS
Years Ended December 31, 1994, 1993, and 1992
(In Thousands)

Column A	Column B	Column C		Column D	Column E
		Additions		Other Changes	
Description	Balance at Beginning of Period	Charged to Income	Charged to Other Accounts	Deductions from Provisions (Note 1)	Balance at End of Period
Year ended December 31, 1994					
Accumulated Provisions Deducted from Assets--					
Doubtful Accounts	$1,075	$2,023	-	$1,923	$1,175
Accumulated Provisions Not Deducted from Assets:					
Property insurance	$2,388	$3,120	-	$4,694	814
Injuries and damages (Note 2)	4,779	5,848	-	3,277	7,350
Environmental	1,237	16,868	-	1,711	16,394
Total	$8,404	$25,836	-	$9,682	$24,558
Year ended December 31, 1993					
Accumulated Provisions Deducted from Assets--					
Doubtful Accounts	$1,956	$337	-	$1,218	$1,075
Accumulated Provisions Not Deducted from Assets:					
Property insurance	$2,474	$1,800	-	$1,886	$2,388
Injuries and damages (Note 2)	6,153	2,748	-	4,122	4,779
Environmental	700	550	-	13	1,237
Total	$9,327	$5,098	-	$6,021	$8,404
Year ended December 31, 1992					
Accumulated Provisions Deducted from Assets--					
Doubtful Accounts	$1,956	$1,324	-	$1,324	$1,956
Accumulated Provisions Not Deducted from Assets:					
Property insurance	$9,174	$4,300	-	$11,000	$2,474
Injuries and damages (Note 2)	6,153	2,283	-	2,283	6,153
Environmental	700	-	-	-	700
Total	$16,027	$6,583	-	$13,283	$9,327

Notes:

(1) Deductions from provisions represent losses or expenses for which the respective provisions were created. In the case of the provision for doubtful accounts, such deductions are reduced by recoveries of amounts previously written off.

(2) Injuries and damages provision is provided to absorb all current expenses as appropriate and for the estimated cost of settling claims for injuries and damages.

MISSISSIPPI POWER & LIGHT COMPANY

SCHEDULE II - VALUATION AND QUALIFYING ACCOUNTS

Years Ended December 31, 1994, 1993, and 1992

(In Thousands)

Column A	Column B	Column C		Column D	Column E
		Additions		Other Changes	
Description	Balance at Beginning of Period	Charged to Income	Charged to Other Accounts (Note 1)	Deductions from Provisions (Note 2)	Balance at End of Period
Year ended December 31, 1994					
Accumulated Provisions Deducted from Assets--					
Doubtful Accounts	$2,470	$1,897	-	$2,297	$2,070
Accumulated Provisions Not Deducted from Assets:					
Property insurance	$2,554	$1,520	-	$295	$3,779
Injuries and damages (Note 3)	3,478	365	-	118	3,725
Environmental	500	300	-	116	684
Total	$6,532	$2,185	-	$529	$8,188
Year ended December 31, 1993					
Accumulated Provisions Deducted from Assets--					
Doubtful Accounts	$1,274	$3,629	-	$2,433	$2,470
Accumulated Provisions Not Deducted from Assets:					
Property insurance	$2,051	$1,521	-	$1,018	$2,554
Injuries and damages (Note 3)	1,645	3,202	-	1,369	3,478
Environmental	500	-	-	-	500
Total	$4,196	$4,723	-	$2,387	$6,532
Year ended December 31, 1992					
Accumulated Provisions Deducted from Assets--					
Doubtful Accounts	$1,389	$834	-	$949	$1,274
Accumulated Provisions Not Deducted from Assets:					
Property insurance	$3,300	$1,520	-	$2,769	$2,051
Injuries and damages (Note 3)	1,863	333	20	571	1,645
Environmental	500	-	-	-	500
Total	$5,663	$1,853	$20	$3,340	$4,196

Notes

(1) Charged to clearing and other accounts.

(2) Deductions from provisions represent losses or expenses for which the respective provisions were created. In the case of the provision for doubtful accounts, such deductions are reduced by recoveries of amounts previously written off.

(3) Injuries and damages provision is provided to absorb all current expenses as appropriate and for the estimated cost of settling claims for injuries and damages.

NEW ORLEANS PUBLIC SERVICE INC.

SCHEDULE II - VALUATION AND QUALIFYING ACCOUNTS
Years Ended December 31, 1994, 1993, and 1992
(In Thousands)

Column A	Column B	Column C		Column D	Column E
		Additions		Other Changes	
Description	Balance at Beginning of Period	Charged to Income	Charged to Other Accounts	Deductions from Provisions (Note 1)	Balance at End of Period
Year ended December 31, 1994					
Accumulated Provisions Deducted from Assets--					
Doubtful Accounts	$830	$1,678	-	$1,678	$830
Accumulated Provisions Not Deducted from Assets:					
Property insurance	$15,911	-	-	-	$15,911
Injuries and damages (Note 2)	2,111	494	-	1,196	1,409
Environmental	40	25	-	68	(3)
Total	$18,062	$519	-	$1,264	$17,317
Year ended December 31, 1993					
Accumulated Provisions Deducted from Assets--					
Doubtful Accounts	$1,350	$1,160	-	$1,680	$830
Accumulated Provisions Not Deducted from Assets:					
Property insurance	$15,470	$441	-	-	$15,911
Injuries and damages (Note 2)	2,329	1,682	-	1,900	2,111
Environmental	40	-	-	-	40
Total	$17,839	$2,123	-	$1,900	$18,062
Year ended December 31, 1992					
Accumulated Provisions Deducted from Assets--					
Doubtful Accounts	$1,350	$1,499	-	$1,499	$1,350
Accumulated Provisions Not Deducted from Assets:					
Property insurance	$14,755	$1,000	-	$285	$15,470
Injuries and damages (Note 2)	2,344	1,351	-	1,366	2,329
Environmental	40	-	-	-	40
Total	$17,139	$2,351	-	$1,651	$17,839

Notes

(1) Deductions from provisions represent losses or expenses for which the respective provisions were created. In the case of the provision for doubtful accounts, such deductions are reduced by recoveries of amounts previously written off.

(2) Injuries and damages provision is provided to absorb all current expenses as appropriate and for the estimated cost of settling claims for injuries and damages.

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EXHIBIT INDEX

The following exhibits indicated by an asterisk preceding the exhibit number are filed herewith. The balance of the exhibits have heretofore been filed with the SEC, respectively, as the exhibits and in the file numbers indicated and are incorporated herein by reference. The exhibits marked with a (+) are management contracts or compensatory plans or arrangements required to be filed herewith and required to be identified as such by Item 14 of Form 10-K. Reference is made to a duplicate list of exhibits being filed as a part of this Form 10-K, which list, prepared in accordance with Item 102 of Regulation S-T of the SEC, immediately precedes the exhibits being physically filed with this Form 10-K.

(3) (i) Articles of Incorporation

Entergy Corporation

(a)	1	--	Certificate of Incorporation of Entergy Corporation (A-1(a) to Rule 24 Certificate in 70-8059).

System Energy

(b)	1	--	Amended and Restated Articles of Incorporation of System Energy, as executed April 28, 1989 (A-1(a) to Form U-1 in 70-5399).

AP&L

(c)	1	--	Amended and Restated Articles of Incorporation of AP&L, as amended (4(c) in 33-50289).

GSU

(d)	1	--	Restated Articles of Incorporation, as amended, of GSU (A-11 in 70-8059).
(d)	2	--	Statement of Resolution amending Restated Articles of Incorporation, as amended, of GSU (A-11(a) in 70-8059).

LP&L

(e)	1	--	Restated Articles of Incorporation of LP&L, as amended (3(a) to Form 10-Q for the quarter ended June 30, 1994 in 1-8474).

MP&L

(f)	1	--	Restated Articles of Incorporation of MP&L, as amended (3(b) to Form 10-Q for the quarter ended June 30, 1994 in 0-320).
*(f)	2	--	Articles of Amendment to Restated Articles of Incorporation of MP&L, as amended, as executed January 18, 1995 and March 7, 1995.

NOPSI

(g)	1	--	Restatement of Articles of Incorporation of NOPSI, as amended (3(c) to Form 10-Q for the quarter ended June 30, 1994 in 0-5807).

(3) (ii) By-Laws

(a) -- By-Laws of Entergy Corporation (A-2(a) to Rule 24 Certificate in 70-8059).

(b) -- By-Laws of System Energy (A-2(a) in 70-5399).

(c) -- By-Laws of AP&L (4(f) in 33-50289).

(d) -- By-Laws of GSU (A-12 in 70-8059).

(e) -- By-Laws of LP&L (A-4 in 70-6962).

(f) -- By-Laws of MP&L (3(ii)(f) to Form 10-K for the year ended December 31, 1993 in 0-320).

(g) -- By-Laws of NOPSI (3(b) to Form 10-Q for the quarter ended September 30, 1989 in 0-5807).

(4) Instruments Defining Rights of Security Holders, Including Indentures

Entergy Corporation

(a) 1 -- See (4)(b) through (4)(g) below for instruments defining the rights of holders of long-term debt of System Energy, AP&L, GSU, LP&L, MP&L and NOPSI.

(a) 2 -- Revolving Credit Agreement, dated as of January 31, 1989 between System Fuels and Bank of America National Trust and Savings Association (B-1(c) to Rule 24 Certificate, dated February 1, 1989, in 70-7574), as amended by First Amendment to Revolving Credit Agreement, dated as of August 28, 1990 (A to Rule 24 Certificate, dated October 31, 1990, in 70-7574).

(a) 3 -- Security Agreement dated as of January 31, 1989 between System Fuels and Bank of America National Trust and Savings Association (B-3(c) to Rule 24 Certificate, dated February 1, 1989, in 70-7574).

(a) 4 -- Credit Agreement, dated as of October 3, 1989, between System Fuels and The Yasuda Trust and Banking Co., Ltd., New York Branch, as agent (B-1(c) to Rule 24 Certificate, dated October 6, 1989, in 70-7668).

(a) 5 -- First Amendment, dated as of March 1, 1992, to Credit Agreement, dated as of October 3, 1989, between System Fuels and The Yasuda Trust and Banking Co., Ltd., New York Branch, as agent (4(a)5 to Form 10-K for the year ended December 31, 1991 in 1-3517).

(a) 6 -- Second Amendment, dated as of September 30, 1992, to Credit Agreement dated as of October 3, 1989, between System Fuels and The Yasuda Trust and Banking Co., Ltd., New York Branch, as agent (4(a)6 to Form 10-K for the year ended December 31, 1992 in 1-3517).

(a) 7 -- Security Agreement, dated as of October 3, 1989, as amended, between System Fuels and The Yasuda Trust and Banking Co., Ltd., New York Branch, as agent (B-3(c) to Rule 24 Certificate, dated October 6, 1989, in 70-7668), as amended by First Amendment to

Security Agreement, dated as of March 14, 1990 (A to Rule 24 Certificate, dated March 7, 1990, in 70-7668).

(a) 8 -- Consent and Agreement, dated as of October 3, 1989, among System Fuels, The Yasuda Trust and Banking Co., Ltd., New York Branch, as agent, AP&L, LP&L, and System Energy (B-5(c) to Rule 24 Certificate, dated October 6, 1989, in 70-7668).

System Energy

(b) 1 -- Mortgage and Deed of Trust, as amended by nineteen Supplemental Indentures (A-1 in 70-5890 (Mortgage); B and C to Rule 24 Certificate in 70-5890 (First); B to Rule 24 Certificate in 70-6259 (Second); 20(a)-5 to Form 10-Q for the quarter ended June 30, 1981, in 1-3517 (Third); A-1(e)-1 to Rule 24 Certificate in 70-6985 (Fourth); B to Rule 24 Certificate in 70-7021 (Fifth); B to Rule 24 Certificate in 70-7021 (Sixth); A-3(b) to Rule 24 Certificate in 70-7026 (Seventh); A-3(b) to Rule 24 Certificate in 70-7158 (Eighth); B to Rule 24 Certificate in 70-7123 (Ninth); B-1 to Rule 24 Certificate in 70-7272 (Tenth); B-2 to Rule 24 Certificate in 70-7272 (Eleventh); B-3 to Rule 24 Certificate in 70-7272 (Twelfth); B-1 to Rule 24 Certificate in 70-7382 (Thirteenth); B-2 to Rule 24 Certificate in 70-7382 (Fourteenth); A-2(c) to Rule 24 Certificate in 70-7946 (Fifteenth); A-2(c) to Rule 24 Certificate in 70-7946 (Sixteenth); A-2(d) to Rule 24 Certificate in 70-7946 (Seventeenth); A-2(e) to Rule 24 Certificate dated May 4, 1993 in 70-7946 (Eighteenth); and A-2(g) to Rule 24 Certificate dated May 6, 1994, in 70-7946 (Nineteenth)).

(b) 2 -- Facility Lease No. 1, dated as of December 1, 1988, between Meridian Trust Company and Stephen M. Carta (Steven Kaba, successor), as Owner Trustees, and System Energy (B-2(c)(1) to Rule 24 Certificate dated January 9, 1989 in 70-7561), as supplemented by Lease Supplement No. 1 dated as of April 1, 1989 (B-22(b) (1) to Rule 24 Certificate dated April 21, 1989 in 70-7561) and Lease Supplement No. 2 dated as of January 1, 1994 (B-3(d) to Rule 24 Certificate dated January 31, 1994 in 70-8215).

(b) 3 -- Facility Lease No. 2, dated as of December 1, 1988 between Meridian Trust Company and Stephen M. Carta (Steven Kaba, successor), as Owner Trustees, and System Energy (B-2(c)(2) to Rule 24 Certificate dated January 9, 1989 in 70-7561), as supplemented by Lease Supplement No. 1 dated as of April 1, 1989 (B-22(b) (2) to Rule 24 Certificate dated April 21, 1989 in 70-7561) and Lease Supplement No. 2 dated as of January 1, 1994 (B-4(d) Rule 24 Certificate dated January 31, 1994 in 70-8215).

(b) 4 -- Installment Sale Agreement, dated as of December 1, 1983 between System Energy and Claiborne County, Mississippi (B-1 to First Rule 24 Certificate in 70-6913).

(b) 5 -- Indenture of Trust, dated as of December 1, 1983, between Claiborne County, Mississippi and Deposit Guaranty National Bank (A-1 to First Rule 24 Certificate in 70-6913).

(b) 6 -- Installment Sale Agreement, dated as of June 1, 1984, between System Energy and Claiborne County, Mississippi (B-2 to Second Rule 24 Certificate in 70-6913).

(b) 7 -- Indenture of Trust cated as of June 1, 1984, between Claiborne County, Mississippi and Deposit Guaranty National Bank (A-2 to Second Rule 24 Certificate in 70-6913).

(b) 8 -- Installment Sale Agreement, dated as of December 1, 1984, between System Energy and Claiborne County, Mississippi (B-1 to First Rule 24 Certificate in 70-7026).

(b)	9	--	Indenture of Trust, dated as of December 1, 1984, between Claiborne County, Mississippi and Deposit Guaranty National Bank (B-2 to First Rule 24 Certificate in 70-7026).
(b)	10	--	Installment Sale Agreement, dated as of June 15, 1985, between System Energy and Claiborne County, Mississippi (B-1(b) to Third Rule 24 Certificate in 70-7026).
(b)	11	--	Indenture of Trust, dated as of June 15, 1985, between Claiborne County, Mississippi and Deposit Guaranty National Bank (B-2(b) to Third Rule 24 Certificate in 70-7026).
(b)	12	--	Installment Sale Agreement, dated as of May 1, 1986, between System Energy and Claiborne County, Mississippi (B-1(b) to Rule 24 Certificate in 70-7158).
(b)	13	--	Indenture of Trust, dated as of May 1, 1986, between Claiborne County, Mississippi and Deposit Guaranty National Bank (B-2(b) to Rule 24 Certificate in 70-7158).
AP&L			
(c)	1	--	Mortgage and Deed of Trust, as amended by fifty-two Supplemental Indentures (7(d) in 2-5463 (Mortgage); 7(b) in 2-7121 (First); 7(c) in 2-7605 (Second); 7(d) in 2-8100 (Third); 7(a)-4 in 2-8482 (Fourth); 7(a)-5 in 2-9149 (Fifth); 4(a)-6 in 2-9789 (Sixth); 4(a)-7 in 2-10261 (Seventh); 4(a)-8 in 2-11043 (Eighth); 2(b)-9 in 2-11468 (Ninth); 2(b)-10 in 2-15767 (Tenth); D in 70-3952 (Eleventh); D in 70-4099 (Twelfth); 4(d) in 2-23185 (Thirteenth); 2(c) in 2-24414 (Fourteenth); 2(c) in 2-25913 (Fifteenth); 2(c) in 2-28869 (Sixteenth); 2(d) in 2-28869 (Seventeenth); 2(c) in 2-35107 (Eighteenth); 2(d) in 2-36646 (Nineteenth); 2(c) in 2-39253 (Twentieth); 2(c) in 2-41080 (Twenty-first); C-1 to Rule 24 Certificate in 70-5151 (Twenty-second); C-1 to Rule 24 Certificate in 70-5257 (Twenty-third); C to Rule 24 Certificate in 70-5343 (Twenty-fourth); C-1 to Rule 24 Certificate in 70-5404 (Twenty-fifth); C to Rule 24 Certificate in 70-5502 (Twenty-sixth); C-1 to Rule 24 Certificate in 70-5556 (Twenty-seventh); C-1 to Rule 24 Certificate in 70-5693 (Twenty-eighth); C-1 to Rule 24 Certificate in 70-6078 (Twenty-ninth); C-1 to Rule 24 Certificate in 70-6174 (Thirtieth); C-1 to Rule 24 Certificate in 70-6246 (Thirty-first); C-1 to Rule 24 Certificate in 70-6498 (Thirty-second); A-4b-2 to Rule 24 Certificate in 70-6326 (Thirty-third); C-1 to Rule 24 Certificate in 70-6607 (Thirty-fourth); C-1 to Rule 24 Certificate in 70-6650 (Thirty-fifth); C-1 to Rule 24 Certificate, dated December 1, 1982, in 70-6774 (Thirty-sixth); C-1 to Rule 24 Certificate, dated February 17, 1983, in 70-6774 (Thirty-seventh); A-2(a) to Rule 24 Certificate, dated December 5, 1984, in 70-6858 (Thirty-eighth); A-3(a) to Rule 24 Certificate in 70-7127 (Thirty-ninth); A-7 to Rule 24 Certificate in 70-7068 (Fortieth), A-8(b) to Rule 24 Certificate dated July 6, 1989 in 70-7346 (Forty-first); A-8(c) to Rule 24 Certificate, dated February 1, 1990 in 70-7346 (Forty-second); 4 to Form 10-Q for the quarter ended September 30, 1990 in 1-10764 (Forty-third); A-2(a) to Rule 24 Certificate, dated November 30, 1990, in 70-7802 (Forty-fourth); A-2(b) to Rule 24 Certificate, dated January 24, 1991, in 70-7802 (Forty-fifth); 4(d)(2) in 33-54298 (Forty-sixth); 4(c)(2) to Form 10-K for the year ended December 31, 1992 in 1-10764 (Forty-seventh); 4(b) to Form 10-Q for the quarter ended June 30, 1993 in 1-10764 (Forty-eighth); 4(c) to Form 10-Q for the quarter ended June 30, 1993 in 1-10764 (Forty-ninth); 4(b) to Form 10-Q for the quarter ended September 30, 1993 in 1-10764 (Fiftieth); 4(c) to Form 10-Q for the quarter ended September 30, 1993 in 1-10764 (Fifty-first); and 4(a) to Form 10-Q for the quarter ended June 30, 1994 (Fifty-second)).

GSU

(d) 1 -- Indenture of Mortgage, as amended by certain Supplemental Indentures (B-a-1-1 in Registration No. 2-2449 (Mortgage); 7-A-9 in Registration No. 2-6893 (Seventh); B to Form 8-K dated September 1, 1959 (Eighteenth); B to Form 8-K dated February 1, 1966 (Twenty-second); B to Form 8-K dated March 1, 1967 (Twenty-third); C to Form 8-K dated March 1, 1968 (Twenty-fourth); B to Form 8-K dated November 1, 1968 (Twenty-fifth); B to Form 8-K dated April 1, 1969 (Twenty-sixth); 2-A-8 in Registration No. 2-66612 (Thirty-eighth); 4-2 to Form 10-K for the year ended December 31, 1984 in 1-2703 (Forty-eighth); 4-2 to Form 10-K for the year ended December 31, 1988 in 1-2703 (Fifty-second); 4 to Form 10-K for the year ended December 31, 1991 in 1-2703 (Fifty-third); 4 to Form 8-K dated July 29, 1992 in 1-2703 (Fifth-fourth); 4 to Form 10-K dated December 31, 1992 in 1-2703 (Fifty-fifth); 4 to Form 10-Q for the quarter ended March 31, 1993 in 1-2703 (Fifty-sixth); and 4-2 to Amendment No. 9 to Registration No. 2-76551 (Fifty-seventh)).

(d) 2 -- Indenture, dated March 21, 1939, accepting resignation of The Chase National Bank of the City of New York as trustee and appointing Central Hanover Bank and Trust Company as successor trustee (B-a-1-6 in Registration No. 2-4076).

(d) 3 -- Trust Indenture for 9.72% Debentures due July 1, 1998 (4 in Registration No. 33-40113).

LP&L

(e) 1 -- Mortgage and Deed of Trust, as amended by forty-nine Supplemental Indentures (7(d) in 2-5317 (Mortgage); 7(b) in 2-7408 (First); 7(c) in 2-8636 (Second); 4(b)-3 in 2-10412 (Third); 4(b)-4 in 2-12264 (Fourth); 2(b)-5 in 2-12936 (Fifth); D in 70-3862 (Sixth); 2(b)-7 in 2-22340 (Seventh); 2(c) in 2-24429 (Eighth); 4(c)-9 in 2-25801 (Ninth); 4(c)-10 in 2-26911 (Tenth); 2(c) in 2-28123 (Eleventh); 2(c) in 2-34659 (Twelfth); C to Rule 24 Certificate in 70-4793 (Thirteenth); 2(b)-2 in 2-38378 (Fourteenth); 2(b)-2 in 2-39437 (Fifteenth); 2(b)-2 in 2-42523 (Sixteenth); C to Rule 24 Certificate in 70-5242 (Seventeenth); C to Rule 24 Certificate in 70-5330 (Eighteenth); C-1 to Rule 24 Certificate in 70-5449 (Nineteenth); C-1 to Rule 24 Certificate in 70-5550 (Twentieth); A-6(a) to Rule 24 Certificate in 70-5598 (Twenty-first); C-1 to Rule 24 Certificate in 70-5711 (Twenty-second); C-1 to Rule 24 Certificate in 70-5919 (Twenty-third); C-1 to Rule 24 Certificate in 70-6102 (Twenty-fourth); C-1 to Rule 24 Certificate in 70-6169 (Twenty-fifth); C-1 to Rule 24 Certificate in 70-6278 (Twenty-sixth); C-1 to Rule 24 Certificate in 70-6355 (Twenty-seventh); C-1 to Rule 24 Certificate in 70-6508 (Twenty-eighth); C-1 to Rule 24 Certificate in 70-6556 (Twenty-ninth); C-1 to Rule 24 Certificate in 70-6635 (Thirtieth); C-1 to Rule 24 Certificate in 70-6834 (Thirty-first); C-1 to Rule 24 Certificate in 70-6886 (Thirty-second); C-1 to Rule 24 Certificate in 70-6993 (Thirty-third); C-2 to Rule 24 Certificate in 70-6993 (Thirty-fourth); C-3 to Rule 24 Certificate in 70-6993 (Thirty-fifth); A-2(a) to Rule 24 Certificate in 70-7166 (Thirty-sixth); A-2(a) in 70-7226 (Thirty-seventh); C-1 to Rule 24 Certificate in 70-7270 (Thirty-eighth); 4(a) to Quarterly Report on Form 10-Q for the quarter ended June 30, 1988, in 1-8474 (Thirty-ninth); A-2(b) to Rule 24 Certificate in 70-7553 (Fortieth); A-2(d) to Rule 24 Certificate in 70-7553 (Forty-first); A-3(a) to Rule 24 Certificate in 70-7822 (Forty-second); A-3(b) to Rule 24 Certificate in 70-7822 (Forty-third); A-2(b) to Rule 24 Certificate in File No. 70-7822 (Forty-fourth); A-3(c) to Rule 24 Certificate in 70-7822 (Forty-fifth); A-2(c) to Rule 24 Certificate dated April 7, 1993 in 70-7822 (Forty-sixth); A-3(d) to Rule 24 Certificate dated June 4, 1993 in 70-7822 (Forth-seventh); A-3(e) to

Rule 24 Certificate dated December 21, 1993 in 70-7822 (Forty-eighth); and A-3(f) to Rule 24 Certificate dated August 1, 1994 in 70-7822 (Forty-ninth).

(c) 2 -- Facility Lease No. 1, dated as of September 1, 1989, between First National Bank of Commerce, as Owner Trustee, and LP&L (4(c)-1 in Registration No. 33-30660).

(c) 3 -- Facility Lease No. 2, dated as of September 1, 1989, between First National Bank of Commerce, as Owner Trustee, and LP&L (4(c)-2 in Registration No. 33-30660).

(c) 4 -- Facility Lease No. 3, dated as of September 1, 1989, between First National Bank of Commerce, as Owner Trustee, and LP&L (4(c)-3 in Registration No. 33-30660).

MP&L

(f) 1 -- Mortgage and Deed of Trust, as amended by twenty-five Supplemental Indentures (7(d) in 2-5437 (Mortgage); 7(b) in 2-7051 (First); 7(c) in 2-7763 (Second); 7(d) in 2-8484 (Third); 4(b)-4 in 2-10059 (Fourth); 2(b)-5 in 2-13942 (Fifth); A-11 to Form U-1 in 70-4116 (Sixth); 2(b)-7 in 2-23084 (Seventh); 4(c)-9 in 2-24234 (Eighth); 2(b)-9(a) in 2-25502 (Ninth); A-11(a) to Form U-1 in 70-4803 (Tenth); A-12(a) to Form U-1 in 70-4892 (Eleventh); A-13(a) to Form U-1 in 70-5165 (Twelfth); A-14(a) to Form U-1 in 70-5286 (Thirteenth); A-15(a) to Form U-1 in 70-5371 (Fourteenth); A-16(a) to Form U-1 in 70-5417 (Fifteenth); A-17 to Form U-1 in 70-5484 (Sixteenth); 2(a)-19 in 2-54234 (Seventeenth); C-1 to Rule 24 Certificate in 70-6619 (Eighteenth); A-2(c) to Rule 24 Certificate in 70-6672 (Nineteenth); A-2(d) to Rule 24 Certificate in 70-6672 (Twentieth); C-1(a) to Rule 24 Certificate in 70-6816 (Twenty-first); C-1(a) to Rule 24 Certificate in 70-7020 (Twenty-second); C-1(b) to Rule 24 Certificate in 70-7020 (Twenty-third); C-1(a) to Rule 24 Certificate in 70-7230 (Twenty-fourth); and A-2(a) to Rule 24 Certificate in 70-7419 (Twenty-fifth)).

(f) 2 -- Mortgage and Deed of Trust, dated as of February 1, 1988, as amended by nine Supplemental Indentures (A-2(a)-2 to Rule 24 Certificate in 70-7461 (Mortgage); A-2(b)-2 in 70-7461 (First); A-5(b) to Rule 24 Certificate in 70-7419 (Second); A-4(b) to Rule 24 Certificate in 70-7554 (Third); A-1(b)-1 to Rule 24 Certificate in 70-7737 (Fourth); A-2(b) to Rule 24 Certificate dated November 24, 1992 in 70-7914 (Fifth); A-2(c) to Rule 24 Certificate dated January 22, 1993 in 70-7914 (Sixth); A-2(g) to Form U-1 in 70-7914 (Seventh); A-2(i) to Rule 24 Certificate dated November 10, 1993 in 70-7914 (Eighth); and A-2(j) to Rule 24 Certificate dated July 22, 1994 in 70-7914 (Ninth)).

NOPSI

(g) 1 -- Mortgage and Deed of Trust, as amended by eleven Supplemental Indentures (B-3 in 2-5411 (Mortgage); 7(b) in 2-7674 (First); 4(a)-2 in 2-10126 (Second); 4(b) in 2-12136 (Third); 2(b)-4 in 2-17959 (Fourth); 2(b)-5 in 2-19807 (Fifth); D to Rule 24 Certificate in 70-4023 (Sixth); 2(c) in 2-24523 (Seventh); 4(c)-9 in 2-26031 (Eighth); 2(a)-3 in 2-50438 (Ninth); 2(a)-3 in 2-62575 (Tenth); and A-2(b) to Rule 24 Certificate in 70-7267 (Eleventh)).

(g) 2 -- Mortgage and Deed of Trust, dated as of May 1, 1987, as amended by four Supplemental Indentures (A-2(c) to Rule 24 Certificate in 70-7350 (Mortgage); A-5(b) to Rule 24 Certificate in 70-7350 (First); A-4(b) to Rule 24 Certificate in 70-7448 (Second); 4(f)4 to Form 10-K for the year ended December 31, 1992 in 0-5807 (Third); and 4(a) to Form 10-Q for the quarter ended September 30, 1993 in 0-5807 (Fourth)).

GSU

(d) 1 -- Indenture of Mortgage, as amended by certain Supplemental Indentures (B-a-1-1 in Registration No. 2-2449 (Mortgage); 7-A-9 in Registration No. 2-6893 (Seventh); B to Form 8-K dated September 1, 1959 (Eighteenth); B to Form 8-K dated February 1, 1966 (Twenty-second); B to Form 8-K dated March 1, 1967 (Twenty-third); C to Form 8-K dated March 1, 1968 (Twenty-fourth); B to Form 8-K dated November 1, 1968 (Twenty-fifth); B to Form 8-K dated April 1, 1969 (Twenty-sixth); 2-A-8 in Registration No. 2-66612 (Thirty-eighth); 4-2 to Form 10-K for the year ended December 31, 1984 in 1-2703 (Forty-eighth); 4-2 to Form 10-K for the year ended December 31, 1988 in 1-2703 (Fifty-second); 4 to Form 10-K for the year ended December 31, 1991 in 1-2703 (Fifty-third); 4 to Form 8-K dated July 29, 1992 in 1-2703 (Fifth-fourth); 4 to Form 10-K dated December 31, 1992 in 1-2703 (Fifty-fifth); 4 to Form 10-Q for the quarter ended March 31, 1993 in 1-2703 (Fifty-sixth); and 4-2 to Amendment No. 9 to Registration No. 2-76551 (Fifty-seventh)).

(d) 2 -- Indenture, dated March 21, 1939, accepting resignation of The Chase National Bank of the City of New York as trustee and appointing Central Hanover Bank and Trust Company as successor trustee (B-a-1-6 in Registration No. 2-4076).

(d) 3 -- Trust Indenture for 9.72% Debentures due July 1, 1998 (4 in Registration No. 33-40113).

LP&L

(e) 1 -- Mortgage and Deed of Trust, as amended by forty-nine Supplemental Indentures (7(d) in 2-5317 (Mortgage); 7(b) in 2-7408 (First); 7(c) in 2-8636 (Second); 4(b)-3 in 2-10412 (Third); 4(b)-4 in 2-12264 (Fourth); 2(b)-5 in 2-12936 (Fifth); D in 70-3862 (Sixth); 2(b)-7 in 2-22340 (Seventh); 2(c) in 2-24429 (Eighth); 4(c)-9 in 2-25801 (Ninth); 4(c)-10 in 2-26911 (Tenth); 2(c) in 2-28123 (Eleventh); 2(c) in 2-34659 (Twelfth); C to Rule 24 Certificate in 70-4793 (Thirteenth); 2(b)-2 in 2-38378 (Fourteenth); 2(b)-2 in 2-39437 (Fifteenth); 2(b)-2 in 2-42523 (Sixteenth); C to Rule 24 Certificate in 70-5242 (Seventeenth); C to Rule 24 Certificate in 70-5330 (Eighteenth); C-1 to Rule 24 Certificate in 70-5449 (Nineteenth); C-1 to Rule 24 Certificate in 70-5550 (Twentieth); A-6(a) to Rule 24 Certificate in 70-5598 (Twenty-first); C-1 to Rule 24 Certificate in 70-5711 (Twenty-second); C-1 to Rule 24 Certificate in 70-5919 (Twenty-third); C-1 to Rule 24 Certificate in 70-6102 (Twenty-fourth); C-1 to Rule 24 Certificate in 70-6169 (Twenty-fifth); C-1 to Rule 24 Certificate in 70-6278 (Twenty-sixth); C-1 to Rule 24 Certificate in 70-6355 (Twenty-seventh); C-1 to Rule 24 Certificate in 70-6508 (Twenty-eighth); C-1 to Rule 24 Certificate in 70-6556 (Twenty-ninth); C-1 to Rule 24 Certificate in 70-6635 (Thirtieth); C-1 to Rule 24 Certificate in 70-6834 (Thirty-first); C-1 to Rule 24 Certificate in 70-6886 (Thirty-second); C-1 to Rule 24 Certificate in 70-6993 (Thirty-third); C-2 to Rule 24 Certificate in 70-6993 (Thirty-fourth); C-3 to Rule 24 Certificate in 70-6993 (Thirty-fifth); A-2(a) to Rule 24 Certificate in 70-7166 (Thirty-sixth); A-2(a) in 70-7226 (Thirty-seventh); C-1 to Rule 24 Certificate in 70-7270 (Thirty-eighth); 4(a) to Quarterly Report on Form 10-Q for the quarter ended June 30, 1988, in 1-3474 (Thirty-ninth); A-2(b) to Rule 24 Certificate in 70-7553 (Fortieth); A-2(d) to Rule 24 Certificate in 70-7553 (Forty-first); A-3(a) to Rule 24 Certificate in 70-7822 (Forty-second); A-3(b) to Rule 24 Certificate in 70-7822 (Forty-third); A-2(b) to Rule 24 Certificate in File No. 70-7822 (Forty-fourth); A-3(c) to Rule 24 Certificate in 70-7822 (Forty-fifth); A-2(c) to Rule 24 Certificate dated April 7, 1993 in 70-7822 (Forty-sixth); A-3(d) to Rule 24 Certificate dated June 4, 1993 in 70-7822 (Forth-seventh); A-3(e) to

Rule 24 Certificate dated December 21, 1993 in 70-7822 (Forty-eighth); and A-3(f) to Rule 24 Certificate dated August 1, 1994 in 70-7822 (Forty-ninth).

(c) 2 -- Facility Lease No. 1, dated as of September 1, 1989, between First National Bank of Commerce, as Owner Trustee, and LP&L (4(c)-1 in Registration No. 33-30660).

(c) 3 -- Facility Lease No. 2, dated as of September 1, 1989, between First National Bank of Commerce, as Owner Trustee, and LP&L (4(c)-2 in Registration No. 33-30660).

(c) 4 -- Facility Lease No. 3, dated as of September 1, 1989, between First National Bank of Commerce, as Owner Trustee, and LP&L (4(c)-3 in Registration No. 33-30660).

MP&L

(f) 1 -- Mortgage and Deed of Trust, as amended by twenty-five Supplemental Indentures (7(d) in 2-5437 (Mortgage); 7(b) in 2-7051 (First); 7(c) in 2-7763 (Second); 7(d) in 2-8484 (Third); 4(b)-4 in 2-10059 (Fourth); 2(b)-5 in 2-13942 (Fifth); A-11 to Form U-1 in 70-4116 (Sixth); 2(b)-7 in 2-23084 (Seventh); 4(c)-9 in 2-24234 (Eighth); 2(b)-9(a) in 2-25502 (Ninth); A-11(a) to Form U-1 in 70-4803 (Tenth); A-12(a) to Form U-1 in 70-4892 (Eleventh); A-13(a) to Form U-1 in 70-5165 (Twelfth); A-14(a) to Form U-1 in 70-5286 (Thirteenth); A-15(a) to Form U-1 in 70-5371 (Fourteenth); A-16(a) to Form U-1 in 70-5417 (Fifteenth); A-17 to Form U-1 in 70-5484 (Sixteenth); 2(a)-19 in 2-54234 (Seventeenth); C-1 to Rule 24 Certificate in 70-6619 (Eighteenth); A-2(c) to Rule 24 Certificate in 70-6672 (Nineteenth); A-2(d) to Rule 24 Certificate in 70-6672 (Twentieth); C-1(a) to Rule 24 Certificate in 70-6816 (Twenty-first); C-1(a) to Rule 24 Certificate in 70-7020 (Twenty-second); C-1(b) to Rule 24 Certificate in 70-7020 (Twenty-third); C-1(a) to Rule 24 Certificate in 70-7230 (Twenty-fourth); and A-2(a) to Rule 24 Certificate in 70-7419 (Twenty-fifth)).

(f) 2 -- Mortgage and Deed of Trust, dated as of February 1, 1988, as amended by nine Supplemental Indentures (A-2(a)-2 to Rule 24 Certificate in 70-7461 (Mortgage); A-2(b)-2 in 70-7461 (First); A-5(b) to Rule 24 Certificate in 70-7419 (Second); A-4(b) to Rule 24 Certificate in 70-7554 (Third); A-1(b)-1 to Rule 24 Certificate in 70-7737 (Fourth); A-2(b) to Rule 24 Certificate dated November 24, 1992 in 70-7914 (Fifth); A-2(e) to Rule 24 Certificate dated January 22, 1993 in 70-7914 (Sixth); A-2(g) to Form U-1 in 70-7914 (Seventh); A-2(i) to Rule 24 Certificate dated November 10, 1993 in 70-7914 (Eighth); and A-2(j) to Rule 24 Certificate dated July 22, 1994 in 70-7914 (Ninth)).

NOPSI

(g) 1 -- Mortgage and Deed of Trust, as amended by eleven Supplemental Indentures (B-3 in 2-5411 (Mortgage); 7(b) in 2-7674 (First); 4(a)-2 in 2-10126 (Second); 4(b) in 2-12136 (Third); 2(b)-4 in 2-17959 (Fourth); 2(b)-5 in 2-19807 (Fifth); D to Rule 24 Certificate in 70-4023 (Sixth); 2(c) in 2-24523 (Seventh); 4(c)-9 in 2-26031 (Eighth); 2(a)-3 in 2-50438 (Ninth); 2(a)-3 in 2-62575 (Tenth); and A-2(b) to Rule 24 Certificate in 70-7262 (Eleventh)).

(g) 2 -- Mortgage and Deed of Trust, dated as of May 1, 1987, as amended by four Supplemental Indentures (A-2(c) to Rule 24 Certificate in 70-7350 (Mortgage); A-5(b) to Rule 24 Certificate in 70-7350 (First); A-4(b) to Rule 24 Certificate in 70-7448 (Second); 4(f)4 to Form 10-K for the year ended December 31, 1992 in 0-5807 (Third); and 4(a) to Form 10-Q for the quarter ended September 30, 1993 in 0-5807 (Fourth)).

(10) Material Contracts

Entergy Corporation

(a)	1	--	Agreement, dated April 23, 1982, among certain System companies, relating to System Planning and Development and Intra-System Transactions (10(a)1 to Form 10-K for the fiscal year ended December 31, 1982, in 1-3517).
(a)	2	--	Middle South Utilities System Agency Agreement, dated December 11, 1970 (5(a)-2 in 2-41080).
(a)	3	--	Amendment, dated February 10, 1971, to Middle South Utilities System Agency Agreement, dated December 11, 1970 (5(a)-4 in 2-41080).
(a)	4	--	Amendment, dated May 12, 1988, to Middle South Utilities System Agency Agreement, dated December 11, 1970 (5(a)-4 in 2-41080).
(a)	5	--	Middle South Utilities System Agency Coordination Agreement, dated December 11, 1970 (5(a)-3 in 2-41080).
(a)	6	--	Service Agreement with Entergy Services, dated as of April 1, 1963 (5(a)-5 in 2-41080).
(a)	7	--	Amendment, dated January 1, 1972, to Service Agreement with Entergy Services (5(a)-6 in 2-43175).
(a)	8	--	Amendment, dated April 27, 1984, to Service Agreement with Entergy Services (10(a)-7 to Form 10-K for the fiscal year ended December 31, 1984, in 1-3517).
(a)	9	--	Amendment, dated August 1, 1988, to Service Agreement with Entergy Services (10(a)-8 to Form 10-K for the fiscal year ended December 31, 1988, in 1-3517).
(a)	10	--	Amendment, dated January 1, 1991, to Service Agreement with Entergy Services (10(a)-9 to Form 10-K for the fiscal year ended December 31, 1990, in 1-3517).
*(a)	11	--	Amendment, dated January 1, 1992, to Service Agreement with Entergy Services.
(a)	12	--	Availability Agreement, dated June 21, 1974, among System Energy and certain other System companies (B to Rule 24 Certificate, dated June 24, 1974, in 70-5399).
(a)	13	--	First Amendment to Availability Agreement, dated as of June 30, 1977 (B to Rule 24 Certificate, dated June 24, 1977, in 70-5399).
(a)	14	--	Second Amendment to Availability Agreement, dated as of June 15, 1981 (E to Rule 24 Certificate, dated July 1, 1981, in 70-6592).
(a)	15	--	Third Amendment to Availability Agreement, dated as of June 28, 1984 (B-13(a) to Rule 24 Certificate, dated July 6, 1984, in 70-6985).
(a)	16	--	Fourth Amendment to Availability Agreement, dated as of June 1, 1989 (A to Rule 24 Certificate, dated June 8, 1989, in 70-5399).

(a)	17	--	Fourteenth Assignment of Availability Agreement, Consent and Agreement, dated as of June 15, 1985, with Deposit Guaranty National Bank, United States Trust Company of New York and Malcolm J. Hood, as Trustees (B-3(b) to Rule 24 Certificate, dated July 31, 1985, in 70-7026).
(a)	18	--	Fifteenth Assignment of Availability Agreement, Consent and Agreement, dated as of May 1, 1986, with Deposit Guaranty National Bank, United States Trust Company of New York and Malcolm J. Hood, as Trustees (B-3(b) to Rule 24 Certificate, dated June 5, 1986, in 70-7158).
(a)	19	--	Sixteenth Assignment of Availability Agreement, Consent and Agreement, dated as of May 1, 1986, with United States Trust Company of New York and Malcolm J. Hood, as Trustees (C to Rule 24 Certificate, dated June 4, 1986, in 70-7123).
(a)	20	--	Eighteenth Assignment of Availability Agreement, Consent and Agreement, dated as of September 1, 1986, with United States Trust Company of New York and Gerard F. Ganey, as Trustees (C-2 to Rule 24 Certificate, dated October 1, 1986, in 70-7272).
(a)	21	--	Nineteenth Assignment of Availability Agreement, Consent and Agreement, dated as of September 1, 1986, with United States Trust Company of New York and Gerard F. Ganey, as Trustees (C-3 to Rule 24 Certificate, dated October 1, 1986, in 70-7272).
(a)	22	--	Twenty-fourth Assignment of Availability Agreement, Consent and Agreement, dated as of July 1, 1992, with United States Trust Company of New York and Gerard F. Ganey, as Trustees (B-2(b) to Rule 24 Certificate, dated July 14, 1992, in 70-7946).
(a)	23	--	Twenty-fifth Assignment of Availability Agreement, Consent and Agreement, dated as of October 1, 1992, with United States Trust Company of New York and Gerard F. Ganey, as Trustees (B-2(b) to Rule 24 Certificate, dated November 2, 1992, in 70-7946).
(a)	24	--	Twenty-sixth Assignment of Availability Agreement, Consent and Agreement, dated as of October 1, 1992, with United States Trust Company of New York and Gerard F. Ganey, as Trustees (B-2(c) to Rule 24 Certificate, dated November 2, 1992, in 70-7946).
(a)	25	--	Twenty-seventh Assignment of Availability Agreement, Consent and Agreement, dated as of April 1, 1993, with United States Trust Company of New York and Gerard F. Ganey as Trustees (B-2(d) to Rule 24 Certificate dated May 4, 1993 in 70-7946).
(a)	26	--	Twenty-eighth Assignment of Availability Agreement, Consent and Agreement, dated as of December 17, 1993, with Chemical Bank, as Agent (B-2(a) to Rule 24 Certificate dated December 22, 1993 in 70-7561).
(a)	27	--	Twenty-ninth Assignment of Availability Agreement, Consent and Agreement, dated as of April 1, 1994, with United States Trust Company of New York and Gerard F. Ganey as Trustees (B-2(f) to Rule 24 Certificate dated May 6, 1994, in 70-7946).
(a)	28	--	Capital Funds Agreement, dated June 21, 1974, between Entergy Corporation and System Energy (C to Rule 24 Certificate, dated June 24, 1974, in 70-5399).
(a)	29	--	First Amendment to Capital Funds Agreement, dated as of June 1, 1989 (B to Rule 24 Certificate, dated June 8, 1989, in 70-5399).

(a)	30	--	Fourteenth Supplementary Capital Funds Agreement and Assignment, dated as of June 15, 1985, with Deposit Guaranty National Bank, United States Trust Company of New York and Malcolm J. Hood, as Trustees (B-4(b) to Rule 24 Certificate, dated July 31, 1985, in 70-7026).
(a)	31	--	Fifteenth Supplementary Capital Funds Agreement and Assignment, dated as of May 1, 1986, with Deposit Guaranty National Bank, United States Trust Company of New York and Malcolm J. Hood, as Trustees (B-4(b) to Rule 24 Certificate, dated June 5, 1986, in 70-7158).
(a)	32	--	Sixteenth Supplementary Capital Funds Agreement and Assignment, dated as of May 1, 1986, with United States Trust Company of New York and Malcolm J. Hood, as Trustees (D to Rule 24 Certificate, dated June 4, 1986, in 70-7123).
(a)	33	--	Eighteenth Supplementary Capital Funds Agreement and Assignment, dated as of September 1, 1986, with United States Trust Company of New York and Gerard F. Ganey, as Trustees (D-2 to Rule 24 Certificate, dated October 1, 1986, in 70-7272).
(a)	34	--	Nineteenth Supplementary Capital Funds Agreement and Assignment, dated as of September 1, 1986, with United States Trust Company of New York and Gerard F. Ganey, as Trustees (D-3 to Rule 24 Certificate, dated October 1, 1986, in 70-7272).
(a)	35	--	Twenty-fourth Supplementary Capital Funds Agreement and Assignment, dated as of July 1, 1992, with United States Trust Company of New York and Gerard F. Ganey, as Trustees (B-3(b) to Rule 24 Certificate dated July 14, 1992 in 70-7946).
(a)	36	--	Twenty-fifth Supplementary Capital Funds Agreement and Assignment, dated as of October 1, 1992, with United States Trust Company of New York and Gerard F. Ganey, as Trustees (B-3(b) to Rule 24 Certificate dated November 2, 1992 in 70-7946).
(a)	37	--	Twenty-sixth Supplementary Capital Funds Agreement and Assignment, dated as of October 1, 1992, with United States Trust Company of New York and Gerard F. Ganey, as Trustees (B-3(c) to Rule 24 Certificate dated November 2, 1992 in 70-7946).
(a)	38	--	Twenty-seventh Supplementary Capital Funds Agreement and Assignment, dated as of April 1, 1993, with United States Trust Company of New York and Gerard F. Ganey, as Trustees (B-3(d) to Rule 24 Certificate dated May 4, 1993 in 70-7946).
(a)	39	--	Twenty-eighth Supplementary Capital Funds Agreement and Assignment, dated as of December 17, 1993, with Chemical Bank, as Agent (B-3(a) to Rule 24 Certificate dated December 22, 1993 in 70-7561).
(a)	40	--	Twenty-ninth Supplementary Capital Funds Agreement and Assignment, dated as of April 1, 1994, with United States Trust Company of New York and Gerard F. Ganey, as Trustees (B-3(f) to Rule 24 Certificate dated May 6, 1994, in 70-7946).
(a)	41	--	First Amendment to Supplementary Capital Funds Agreements and Assignments, dated as of June 1, 1989, by and between Entergy Corporation, System Energy, Deposit Guaranty National Bank, United States Trust Company of New York and Gerard F. Ganey (C to Rule 24 Certificate, dated June 8, 1989, in 70-7026).

(a)	42	--	First Amendment to Supplementary Capital Funds Agreements and Assignments, dated as of June 1, 1989, by and between Entergy Corporation, System Energy, United States Trust Company of New York and Gerard F. Ganey (C to Rule 24 Certificate, dated June 8, 1989, in 70-7123).
(a)	43	--	First Amendment to Supplementary Capital Funds Agreement and Assignment, dated as of June 1, 1989, by and between Entergy Corporation, System Energy and Chemical Bank (C to Rule 24 Certificate, dated June 8, 1989, in 70-7561).
+(a)	44	--	Agreement between Entergy Corporation and Edwin Lupberger (10(a)-42 to Form 10-K for the fiscal year ended December 31, 1985, in 1-3517).
(a)	45	--	Reallocation Agreement, dated as of July 28, 1981, among System Energy and certain other System companies (B-1(a) in 70-6624).
(a)	46	--	Joint Construction, Acquisition and Ownership Agreement, dated as of May 1, 1980, between System Energy and SMEPA (B-1(a) in 70-6337), as amended by Amendment No. 1, dated as of May 1, 1980 (B-1(c) in 70-6337) and Amendment No. 2, dated as of October 31, 1980 (1 to Rule 24 Certificate, dated October 30, 1981, in 70-6337).
(a)	47	--	Operating Agreement dated as of May 1, 1980, between System Energy and SMEPA (B(2)(a) in 70-6337).
(a)	48	--	Assignment, Assumption and Further Agreement No. 1, dated as of December 1, 1988, among System Energy, Meridian Trust Company and Stephen M. Carta, and SMEPA (B-7(c)(1) to Rule 24 Certificate, dated January 9, 1989, in 70-7561).
(a)	49	--	Assignment, Assumption and Further Agreement No. 2, dated as of December 1, 1988, among System Energy, Meridian Trust Company and Stephen M. Carta, and SMEPA (B-7(c)(2) to Rule 24 Certificate, dated January 9, 1989, in 70-7561).
(a)	50	--	Substitute Power Agreement, dated as of May 1, 1980, among MP&L, System Energy and SMEPA (B(3)(a) in 70-6337).
(a)	51	--	Grand Gulf Unit No. 2 Supplementary Agreement, dated as of February 7, 1986, between System Energy and SMEPA (10(aaa) in 33-4033).
(a)	52	--	Compromise and Settlement Agreement, dated June 4, 1982, between Texaco, Inc. and LP&L (28(a) to Form 8-K, dated June 4, 1982, in 1-3517).
+(a)	53	--	Post-Retirement Plan (10(a)37 to Form 10-K for the fiscal year ended December 31, 1983, in 1-3517).
(a)	54	--	Unit Power Sales Agreement, dated as of June 10, 1982, between System Energy and AP&L, LP&L, MP&L and NOPSI (10(a)-39 to Form 10-K for the fiscal year ended December 31, 1982, in 1-3517).
(a)	55	--	First Amendment to Unit Power Sales Agreement, dated as of June 28, 1984, between System Energy and AP&L, LP&L, MP&L and NOPSI (19 to Form 10-Q for the quarter ended September 30, 1984, in 1-3517).
(a)	56	--	Revised Unit Power Sales Agreement (10(ss) in 33-4033).

(a)	57	--	Middle South Utilities Inc and Subsidiary Companies Intercompany Income Tax Allocation Agreement, dated April 28, 1988 (Exhibit D-1 to Form U5S for the year ended December 31, 1987).
(a)	58	--	First Amendment, dated January 1, 1990, to the Middle South Utilities Inc. and Subsidiary Companies Intercompany Income Tax Allocation Agreement (D-2 to Form U5S for the year ended December 31, 1989).
(a)	59	--	Second Amendment dated January 1, 1992, to the Entergy Corporation and Subsidiary Companies Intercompany Income Tax Allocation Agreement (D-3 to Form U5S for the year ended December 31, 1992).
(a)	60	--	Third Amendment dated January 1, 1994 to Entergy Corporation and Subsidiary Companies Intercompany Income Tax Allocation Agreement (D-3(a) to Form U5S for the year ended December 31, 1993).
(a)	61	--	Guaranty Agreement between Entergy Corporation and AP&L, dated as of September 20, 1990 (B-1(a) to Rule 24 Certificate, dated September 27, 1990, in 70-7757).
(a)	62	--	Guarantee Agreement between Entergy Corporation and LP&L, dated as of September 20, 1990 (B-2(a) to Rule 24 Certificate, dated September 27, 1990, in 70-7757).
(a)	63	--	Guarantee Agreement between Entergy Corporation and System Energy, dated as of September 20, 1990 (B-3(a) to Rule 24 Certificate, dated September 27, 1990, in 70-7757).
(a)	64	--	Loan Agreement between Entergy Operations and Entergy Corporation, dated as of September 20, 1990 (B-12(b) to Rule 24 Certificate, dated June 15, 1990, in 70-7679).
(a)	65	--	Loan Agreement between Entergy Power and Entergy Corporation, dated as of August 28, 1990 (A-4(b) to Rule 24 Certificate, dated September 6, 1990, in 70-7684).
(a)	66	--	Loan Agreement between Entergy Corporation and Entergy Systems and Service, Inc., dated as of December 29, 1992 (A-4(b) to Rule 24 Certificate in 70-7947).
+(a)	67	--	Executive Financial Counseling Program of Entergy Corporation and Subsidiaries (10(a) 52 to Form 10-K for the year ended December 31, 1989, in 1-3517).
+(a)	68	--	Entergy Corporation Annual Incentive Plan (10(a) 54 to Form 10-K for the year ended December 31, 1989, in 1-3517).
+(a)	69	--	Equity Ownership Plan of Entergy Corporation and Subsidiaries (A-4(a) to Rule 24 Certificate, dated May 24, 1991, in 70-7831).
+(a)	70	--	Retired Outside Director Benefit Plan (10(a)63 to Form 10-K for the year ended December 31, 1991, in 1-3517).
+(a)	71	--	Agreement between Entergy Corporation and Jerry D. Jackson. (10(a) 67 to Form 10-K for the year ended December 31, 1992 in 1-3517).

+(a)	72	--	Agreement between Entergy Services, Inc., a subsidiary of Entergy Corporation, and Gerald D. McInvale (10(a) 68 to Form 10-K for the year ended December 31, 1992 in 1-3517).
+(a)	73	--	Supplemental Retirement Plan (10(a) 69 to Form 10-K for the year ended December 31, 1992 in 1-3517).
+(a)	74	--	Defined Contribution Restoration Plan of Entergy Corporation and Subsidiaries (10(a)53 to Form 10-K for the year ended December 31, 1989 in 1-3517).
+(a)	75	--	Amendment No. 1 to the Equity Ownership Plan of Entergy Corporation and Subsidiaries (10(a) 71 to Form 10-K for the year ended December 31, 1992 in 1-3517).
+(a)	76	--	Executive Disability Plan of Entergy Corporation and Subsidiaries (10(a) 72 to Form 10-K for the year ended December 31, 1992 in 1-3517).
+(a)	77	--	Executive Medical Plan of Entergy Corporation and Subsidiaries (10(a) 73 to Form 10-K for the year ended December 31, 1992 in 1-3517).
+(a)	78	--	Stock Plan for Outside Directors of Entergy Corporation and Subsidiaries, as amended (10(a) 74 to Form 10-K for the year ended December 31, 1992 in 1-3517).
+(a)	79	--	Summary Description of Private Ownership Vehicle Plan of Entergy Corporation and Subsidiaries (10(a) 75 to Form 10-K for the year ended December 31, 1992 in 1-3517).
(a)	80	--	Agreement and Plan of Reorganization Between Entergy Corporation and Gulf States Utilities Company, dated June 5, 1992 (1 to Current Report on Form 8-K dated June 5, 1992 in 1-3517).
+(a)	81	--	Amendment to Defined Contribution Restoration Plan of Entergy Corporation and Subsidiaries (10(a) 81 to Form 10-K for the year ended December 31, 1993 in 1-11299).
+(a)	82	--	System Executive Retirement Plan (10(a) 82 to Form 10-K for the year ended December 31, 1993 in 1-11299).
System Energy			
(b)	1	--	Availability Agreement, dated June 21, 1974, among System Energy and certain other System companies (B to Rule 24 Certificate, dated June 24, 1974, in 70-5399).
(b)	2	--	First Amendment to Availability Agreement, dated as of June 30, 1977 (B to Rule 24 Certificate, dated June 24, 1977, in 70-5399).
(b)	3	--	Second Amendment to Availability Agreement, dated as of June 15, 1981 (E to Rule 24 Certificate, dated July 1, 1981, in 70-6592).
(b)	4	--	Third Amendment to Availability Agreement, dated as of June 28, 1984 (B-13(a) to Rule 24 Certificate, dated July 6, 1984, in 70-6985).
(b)	5	--	Fourth Amendment to Availability Agreement, dated as of June 1, 1989 (A to Rule 24 Certificate, dated June 8, 1989, in 70-5399).

(b)	6	--	Fourteenth Assignment of Availability Agreement, Consent and Agreement, dated as of June 15, 1985, with Deposit Guaranty National Bank, United States Trust Company of New York and Malcolm J. Hood, as Trustees (B-3(b) to Rule 24 Certificate, dated July 31, 1985, in 70-7026).
(b)	7	--	Fifteenth Assignment of Availability Agreement, Consent and Agreement, dated as of May 1, 1986, with United States Trust Company of New York, Malcolm J. Hood, and Deposit Guaranty National Bank, as Trustees (B-3(b) to Rule 24 Certificate, dated June 5, 1986, in 70-7158).
(b)	8	--	Sixteenth Assignment of Availability Agreement, Consent and Agreement, dated as of May 1, 1986, with United States Trust Company of New York and Malcolm J. Hood, as Trustees (C to Rule 24 Certificate, dated June 4, 1986, in 70-7123).
(b)	9	--	Eighteenth Assignment of Availability Agreement, Consent and Agreement, dated as of September 1, 1986, with United States Trust Company of New York and Gerard F. Ganey, as Trustees (C-2 to Rule 24 Certificate, dated October 1, 1986, in 70-7272).
(b)	10	--	Nineteenth Assignment of Availability Agreement, Consent and Agreement, dated as of September 1, 1986, with United States Trust Company of New York and Gerard F. Ganey, as Trustees (C-3 to Rule 24 Certificate, dated October 1, 1986, in 70-7272).
(b)	11	--	Twenty-fourth Assignment of Availability Agreement, Consent and Agreement, dated as of July 1, 1992, with United States Trust Company of New York and Gerard F. Ganey, as Trustees (B-2(b) to Rule 24 Certificate, dated July 14, 1992, in 70-7946).
(b)	12	--	Twenty-fifth Assignment of Availability Agreement, Consent and Agreement, dated as of October 1, 1992, with United States Trust Company of New York and Gerard F. Ganey, as Trustees (B-2(b) to Rule 24 Certificate, dated November 2, 1992, in 70-7946).
(b)	13	--	Twenty-sixth Assignment of Availability Agreement, Consent and Agreement, dated as of October 1, 1992, with United States Trust Company of New York and Gerard F. Ganey, as Trustees (B-2(c) to Rule 24 Certificate, dated November 2, 1992, in 70-7946).
(b)	14	--	Twenty-seventh Assignment of Availability Agreement, Consent and Agreement, dated as of April 1, 1993, with United States Trust Company of New York and Gerard F. Ganey as Trustees (B-2(d) to Rule 24 Certificate dated May 4, 1993 in 70-7946).
(b)	15	--	Twenty-eighth Assignment of Availability Agreement, Consent and Agreement, dated as of December 17, 1993, with Chemical Bank, as Agent (B-2(a) to Rule 24 Certificate dated December 22, 1993 in 70-7561).
(b)	16	--	Twenty-ninth Assignment of Availability Agreement, Consent and Agreement, dated as of April 1, 1994, with United States Trust Company of New York and Gerard F. Ganey as Trustees (B-2(f) to Rule 24 Certificate dated May 6, 1994, in 70-7946).
(b)	17	--	Capital Funds Agreement, dated June 21, 1974, between Entergy Corporation and System Energy (C to Rule 24 Certificate, dated June 24, 1974, in 70-5399).
(b)	18	--	First Amendment to Capital Funds Agreement, dated as of June 1, 1989 (B to Rule 24 Certificate, dated June 8, 1989, in 70-5399).

(b)	19	--	Fourteenth Supplementary Capital Funds Agreement and Assignment, dated as of June 15, 1985, with Deposit Guaranty National Bank, United States Trust Company of New York and Malcolm J. Hood, as Trustees (B-4(b) to Rule 24 Certificate, dated July 31, 1985, in 70-7026).
(b)	20	--	Fifteenth Supplementary Capital Funds Agreement and Assignment, dated as of May 1, 1986, with Deposit Guaranty National Bank, United States Trust Company of New York and Malcolm J. Hood, as Trustees (B-4(b) to Rule 24 Certificate, dated June 5, 1986, in 70-7158).
(b)	21	--	Sixteenth Supplementary Capital Funds Agreement and Assignment, dated as of May 1, 1986, with United States Trust Company of New York and Malcolm J. Hood, as Trustees (D to Rule 24 Certificate, dated June 4, 1986, in 70-7123).
(b)	22	--	Eighteenth Supplementary Capital Funds Agreement and Assignment, dated as of September 1, 1986, with United States Trust Company of New York and Gerard F. Ganey, as Trustees (D-2 to Rule 24 Certificate, dated October 1, 1986, in 70-7272).
(b)	23	--	Nineteenth Supplementary Capital Funds Agreement and Assignment, dated as of September 1, 1986, with United States Trust Company of New York and Gerard F. Ganey, as Trustees (D-3 to Rule 24 Certificate, dated October 1, 1986, in 70-7272).
(b)	24	--	Twenty-fourth Supplementary Capital Funds Agreement and Assignment, dated as of July 1, 1992, with United States Trust Company of New York and Gerard F. Ganey, as Trustees (B-3(b) to Rule 24 Certificate dated July 14, 1992, in 70-7946).
(b)	25	--	Twenty-fifth Supplementary Capital Funds Agreement and Assignment, dated as of October 1, 1992, with United States Trust Company of New York and Gerard F. Ganey, as Trustees (B-3(b) to Rule 24 Certificate dated November 2, 1992, in 70-7946).
(b)	26	--	Twenty-sixth Supplementary Capital Funds Agreement and Assignment, dated as of October 1, 1992, with United States Trust Company of New York and Gerard F. Ganey, as Trustees (B-3(c) to Rule 24 Certificate dated November 2, 1992, in 70-7946).
(b)	27	--	Twenty-seventh Supplementary Capital Funds Agreement and Assignment, dated as of April 1, 1993, with United States Trust Company of New York and Gerard F. Ganey, as Trustees (B-3(d) to Rule 24 Certificate dated May 4, 1993 in 70-7946).
(b)	28	--	Twenty-eighth Supplementary Capital Funds Agreement and Assignment, dated as of December 17, 1993, with Chemical Bank, as Agent (B-3(a) to Rule 24 Certificate dated December 22, 1993 in 70-7561).
(b)	29	--	Twenty-ninth Supplementary Capital Funds Agreement and Assignment, dated as of April 1, 1994, with United States Trust Company of New York and Gerard F. Ganey, as Trustees (B-3(f) to Rule 24 Certificate dated May 6, 1994, in 70-7946).
(b)	30	--	First Amendment to Supplementary Capital Funds Agreements and Assignments, dated as of June 1, 1989, by and between Entergy Corporation, System Energy, Deposit Guaranty National Bank, United States Trust Company of New York and Gerard F. Ganey, as Trustees (C to Rule 24 Certificate, dated June 8, 1989, in 70-7026).

(b)	31	--	First Amendment to Supplementary Capital Funds Agreements and Assignments, dated as of June 1, 1989, by and between Entergy Corporation, System Energy, United States Trust Company of New York and Gerard F. Ganey, as Trustees (C to Rule 24 Certificate, dated June 8, 1989, in 70-7123).
(b)	32	--	First Amendment to Supplementary Capital Funds Agreement and Assignment, dated as of June 1, 1989, by and between Entergy Corporation, System Energy and Chemical Bank (C to Rule 24 Certificate, dated June 8, 1989, in 70-7561).
(b)	33	--	Reallocation Agreement, dated as of July 28, 1981, among System Energy and certain other System companies (B-1(a) in 70-6624).
(b)	34	--	Joint Construction, Acquisition and Ownership Agreement, dated as of May 1, 1980, between System Energy and SMEPA (B-1(a) in 70-6337), as amended by Amendment No. 1, dated as of May 1, 1980 (B-1(c) in 70-6337) and Amendment No. 2, dated as of October 31, 1980 (1 to Rule 24 Certificate, dated October 30, 1981, in 70-6337).
(b)	35	--	Operating Agreement, dated as of May 1, 1980, between System Energy and SMEPA (B(2)(a) in 70-6337).
(b)	36	--	Installment Sale Agreement, dated as of December 1, 1983 between System Energy and Claiborne County, Mississippi (B-1 to First Rule 24 Certificate in 70-6913).
(b)	37	--	Installment Sale Agreement, dated as of June 1, 1984, between System Energy and Claiborne County, Mississippi (B-2 to Second Rule 24 Certificate in 70-6913).
(b)	38	--	Installment Sale Agreement, dated as of December 1, 1984, between System Energy and Claiborne County, Mississippi (B-1 to First Rule 24 Certificate in 70-7026).
(b)	39	--	Installment Sale Agreement, dated as of June 15, 1985, between System Energy and Claiborne County, Mississippi (B-1(b) to Third Rule 24 Certificate in 70-7026).
(b)	40	--	Installment Sale Agreement, dated as of May 1, 1986, between System Energy and Claiborne County, Mississippi (B-1(b) to Rule 24 Certificate in 70-7158).
(b)	41	--	Facility Lease No. 1, dated as of December 1, 1988, between Meridian Trust Company and Stephen M. Carta (Stephen J. Kaba, successor), as Owner Trustees, and System Energy (B-2(c)(1) to Rule 24 Certificate dated January 9, 1989 in 70-7561), as supplemented by Lease Supplement No. 1 dated as of April 1, 1989 (B-22(b) (1) to Rule 24 Certificate dated April 21, 1989 in 70-7561) and Lease Supplement No. 2 dated as of January 1, 1994 (B-3(d) to Rule 24 Certificate dated January 31, 1994 in 70-8215).
(b)	42	--	Facility Lease No. 2, dated as of December 1, 1988 between Meridian Trust Company and Stephen M. Carta (Stephen J. Kaba, successor), as Owner Trustees, and System Energy (B-2(c)(2) to Rule 24 Certificate dated January 9, 1989 in 70-7561), as supplemented by Lease Supplement No. 1 dated as of April 1, 1989 (B-22(b) (2) to Rule 24 Certificate dated April 21, 1989 in 70-7561) and Lease Supplement No. 2 dated as of January 1, 1994 (B-4(d) Rule 24 Certificate dated January 31, 1994 in 70-8215).
(b)	43	--	Assignment, Assumption and Further Agreement No. 1, dated as of December 1, 1988, among System Energy, Meridian Trust Company and Stephen M. Carta, and SMEPA (B-7(c)(1) to Rule 24 Certificate, dated January 9, 1989, in 70-7561).

(b)	44	--	Assignment, Assumption and Further Agreement No. 2, dated as of December 1, 1988, among System Energy, Meridian Trust Company and Stephen M. Carta, and SMEPA (B-7(c)(2) to Rule 24 Certificate, dated January 9, 1989, in 70-7561).
(b)	45	--	Collateral Trust Indenture, dated as of January 1, 1994, among System Energy, GG1B Funding Corporation and Bankers Trust Company, as Trustee (A-3(e) to Rule 24 Certificate dated January 31, 1994, in 70-8215), as supplemented by Supplemental Indenture No. 1 dated January 1, 1994, (A-3(f) to Rule 24 Certificate dated January 31, 1994, in 70-8215).
(b)	46	--	Substitute Power Agreement, dated as of May 1, 1980, among MP&L, System Energy and SMEPA (B(3)(a) in 70-6337).
(b)	47	--	Grand Gulf Unit No. 2 Supplementary Agreement, dated as of February 7, 1986, between System Energy and SMEPA (10(aaa) in 33-4033).
(b)	48	--	Unit Power Sales Agreement, dated as of June 10, 1982, between System Energy and AP&L, LP&L, MP&L and NOPSI (10(a)-39 to Form 10-K for the fiscal year ended December 31, 1982, in 1-3517).
(b)	49	--	First Amendment to the Unit Power Sales Agreement, dated as of June 28, 1984, between System Energy and AP&L, LP&L, MP&L and NOPSI (19 to Form 10-Q for the quarter ended September 30, 1984, in 1-3517).
(b)	50	--	Revised Unit Power Sales Agreement (10(ss) in 33-4033).
(b)	51	--	Fuel Lease, dated as of March 3, 1989, between River Fuel Funding Company #3, Inc. and System Energy (B-1(b) to Rule 24 Certificate, dated March 3, 1989, in 70-7604).
(b)	52	--	Sales Agreement, dated as of June 21, 1974, between System Energy and MP&L (D to Rule 24 Certificate, dated June 26, 1974, in 70-5399).
(b)	53	--	Service Agreement, dated as of June 21, 1974, between System Energy and MP&L (E to Rule 24 Certificate, dated June 26, 1974, in 70-5399).
(b)	54	--	Partial Termination Agreement, dated as of December 1, 1986, between System Energy and MP&L (A-2 to Rule 24 Certificate, dated January 8, 1987, in 70-5399).
(b)	55	--	Middle South Utilities, Inc. and Subsidiary Companies Intercompany Income Tax Allocation Agreement, dated April 28, 1988 (D-1 to Form U5S for the year ended December 31, 1987).
(b)	56	--	First Amendment, dated January 1, 1990 to the Middle South Utilities Inc. and Subsidiary Companies Intercompany Income Tax Allocation Agreement (D-2 to Form U5S for the year ended December 31, 1989).
(b)	57	--	Second Amendment dated January 1, 1992, to the Entergy Corporation and Subsidiary Companies Intercompany Income Tax Allocation Agreement (D-3 to Form U5S for the year ended December 31, 1992).

(b)	58	--	Third Amendment dated January 1, 1994 to Entergy Corporation and Subsidiary Companies Intercompany Income Tax Allocation Agreement (D-3(a) to Form U5S for the year ended December 31, 1993).
(b)	59	--	Service Agreement with Entergy Services, dated as of July 16, 1974, as amended (10(b)-43 to Form 10-K for the fiscal year ended December 31, 1988, in 1-9067).
(b)	60	--	Amendment, dated January 1, 1991, to Service Agreement with Entergy Services (10(b)-45 to Form 10-K for the fiscal year ended December 31, 1990, in 1-9067).
(b)	61	--	Operating Agreement between Entergy Operations and System Energy, dated as of June 6, 1990 (B-3(b) to Rule 24 Certificate, dated June 15, 1990, in 70-7679).
(b)	62	--	Guarantee Agreement between Entergy Corporation and System Energy, dated as of September 20, 1990 (B-3(a) to Rule 24 Certificate, dated September 27, 1990, in 70-7757).
+(b)	63	--	Agreement between System Energy and Donald C. Hintz (10(b)47 to Form 10-K for the year ended December 31, 1991, in 1-9067).
+(b)	64	--	Agreement between Entergy Corporation and Edwin Lupberger (10(a)-42 to Form 10-K for the year ended December 31, 1985 in 1-3517).
+(b)	65	--	Agreement between Entergy Services and Gerald D. McInvale (10(a)-69 to Form 10-K for the year ended December 31, 1992 in 1-3517).
AP&L			
(c)	1	--	Agreement, dated April 23, 1982, among AP&L and certain other System companies, relating to System Planning and Development and Intra-System Transactions (10(a) 1 to Form 10-K for the fiscal year ended December 31, 1982, in 1-3517).
(c)	2	--	Middle South Utilities System Agency Agreement, dated December 11, 1970 (5(a)2 in 2-41080).
(c)	3	--	Amendment, dated February 10, 1971, to Middle South Utilities System Agency Agreement, dated December 11, 1970 (5(a)-4 in 2-41080).
(c)	4	--	Amendment, dated May 12, 1988, to Middle South Utilities System Agency Agreement, dated December 11, 1970 (5(a) 4 in 2-41080).
(c)	5	--	Middle South Utilities System Agency Coordination Agreement, dated December 11, 1970 (5(a)-3 in 2-41080).
(c)	6	--	Service Agreement with Entergy Services, dated as of April 1, 1963 (5(a)-5 in 2-41080).
(c)	7	--	Amendment, dated January 1, 1972, to Service Agreement with Entergy Services (5(a)- 6 in 2-43175).
(c)	8	--	Amendment, dated April 27, 1984, to Service Agreement, with Entergy Services (10(a)- 7 to Form 10-K for the fiscal year ended December 31, 1984, in 1-3517).

(c)	9	--	Amendment, dated August 1, 1988, to Service Agreement with Entergy Services (10(c)- 8 to Form 10-K for the fiscal year ended December 31, 1988, in 1-10764).
(c)	10	--	Amendment, dated January 1, 1991, to Service Agreement with Entergy Services (10(c)-9 to Form 10-K for the fiscal year ended December 31, 1990, in 1-10764).
*(c)	11	--	Amendment, dated January 1, 1992, to Service Agreement with Entergy Services.
(c)	12	--	Availability Agreement, dated June 21, 1974, among System Energy and certain other System companies (B to Rule 24 Certificate, dated June 24, 1974, in 70-5399).
(c)	13	--	First Amendment to Availability Agreement, dated June 30, 1977 (B to Rule 24 Certificate, dated June 24, 1977, in 70-5399).
(c)	14	--	Second Amendment to Availability Agreement, dated as of June 15, 1981 (E to Rule 24 Certificate, dated July 1, 1981, in 70-6592).
(c)	15	--	Third Amendment to Availability Agreement, dated as of June 28, 1984 (B-13(a) to Rule 24 Certificate, dated July 6, 1984, in 70-6985).
(c)	16	--	Fourth Amendment to Availability Agreement, dated as of June 1, 1989 (A to Rule 24 Certificate, dated June 8, 1989, in 70-5399).
(c)	17	--	Fourteenth Assignment of Availability Agreement, Consent and Agreement, dated as of June 15, 1985, with Deposit Guaranty National Bank, United States Trust Company of New York and Malcolm J. Hood, as Trustees (B-3(b) to Rule 24 Certificate, dated July 31, 1985, in 70-7026).
(c)	18	--	Fifteenth Assignment of Availability Agreement, Consent and Agreement, dated as of May 1, 1986, with Deposit Guaranty National Bank, United States Trust Company of New York, and Malcolm J. Hood, as Trustees (B-3(b) to Rule 24 Certificate, dated June 5, 1986, in 70-7158).
(c)	19	--	Sixteenth Assignment of Availability Agreement, Consent and Agreement, dated as of May 1, 1986, with United States Trust Company of New York and Malcolm J. Hood, as Trustees (C to Rule 24 Certificate, dated June 4, 1986, in 70-7123).
(c)	20	--	Eighteenth Assignment of Availability Agreement, Consent and Agreement, dated as of September 1, 1986, with United States Trust Company of New York and Gerard F. Ganey, as Trustees (C-2 to Rule 24 Certificate, dated October 1, 1986, in 70-7272).
(c)	21	--	Nineteenth Assignment of Availability Agreement, Consent and Agreement, dated as of September 1, 1986, with United States Trust Company of New York and Gerard F. Ganey, as Trustees (C-3 to Rule 24 Certificate, dated October 1, 1986, in 70-7272).
(c)	22	--	Twenty-fourth Assignment of Availability Agreement, Consent and Agreement, dated as of July 1, 1992, with United States Trust Company of New York and Gerard F. Ganey, as Trustees (B-2(b) to Rule 24 Certificate, dated July 14, 1992, in 70-7946).
(c)	23	--	Twenty-fifth Assignment of Availability Agreement, Consent and Agreement, dated as of October 1, 1992, with United States Trust Company of New York and Gerard F. Ganey, as Trustees (B-2(b) to Rule 24 Certificate, dated November 2, 1992, in 70-7946).

(c)	24	--	Twenty-sixth Assignment of Availability Agreement, Consent and Agreement, dated as of October 1, 1992, with United States Trust Company of New York and Gerard F. Ganey, as Trustees (B-2(c) to Rule 24 Certificate, dated November 2, 1992, in 70-7946).
(c)	25	--	Twenty-seventh Assignment of Availability Agreement, Consent and Agreement, dated as of April 1, 1993, with United States Trust Company of New York and Gerard F. Ganey as Trustees (B-2(d) to Rule 24 Certificate dated May 4, 1993 in 70-7946).
(c)	26	--	Twenty-eighth Assignment of Availability Agreement, Consent and Agreement, dated as of December 17, 1993, with Chemical Bank, as Agent (B-2(a) to Rule 24 Certificate dated December 22, 1993 in 70-7561).
(c)	27		Twenty-ninth Assignment of Availability Agreement, Consent and Agreement, dated as of April 1, 1994, with United States Trust Company of New York and Gerard F. Ganey, as Trustees (B-2(f) to Rule 24 Certificate dated May 6, 1994, in 70-7946).
(c)	28	--	Agreement, dated August 20, 1954, between AP&L and the United States of America (SPA)(13(h) in 2-11467).
(c)	29	--	Amendment, dated April 19, 1955, to the United States of America (SPA) Contract, dated August 20, 1954 (5(d)-2 in 2-41080).
(c)	30	--	Amendment, dated January 3, 1964, to the United States of America (SPA) Contract, dated August 20, 1954 (5(d)-3 in 2-41080).
(c)	31	--	Amendment, dated September 5, 1968, to the United States of America (SPA) Contract, dated August 20, 1954 (5(d)-4 in 2-41080).
(c)	32	--	Amendment, dated November 19, 1970, to the United States of America (SPA) Contract, dated August 20, 1954 (5(d)-5 in 2-41080).
(c)	33	--	Amendment, dated July 18, 1961, to the United States of America (SPA) Contract, dated August 20, 1954 (5(d)-6 in 2-41080).
(c)	34	--	Amendment, dated December 27, 1961, to the United States of America (SPA) Contract, dated August 20, 1954 (5(d)-7 in 2-41080).
(c)	35	--	Amendment, dated January 25, 1968, to the United States of America (SPA) Contract, dated August 20, 1954 (5(d)-8 in 2-41080).
(c)	36	--	Amendment, dated October 14, 1971, to the United States of America (SPA) Contract, dated August 20, 1954 (5(d)-9 in 2-43175).
(c)	37	--	Amendment, dated January 10, 1977, to the United States of America (SPA) Contract, dated August 20, 1954 (5(d)-10 in 2-60233).
(c)	38	--	Agreement, dated May 14, 1971, between AP&L and the United States of America (SPA) (5(e) in 2-41080).
(c)	39	--	Amendment, dated January 10, 1977, to the United States of America (SPA) Contract, dated May 14, 1971 (5(e)-1 in 2-60233).

(c)	40	--	Contract, dated May 28, 1943, Amendment to Contract, dated July 21, 1949, and Supplement to Amendment to Contract, dated December 30, 1949, between AP&L and McKamie Gas Cleaning Company; Agreements, dated as of September 30, 1965, between AP&L and former stockholders of McKamie Gas Cleaning Company; and Letter Agreement, dated June 22, 1966, by Humble Oil & Refining Company accepted by AP&L on June 24, 1966 (5(k)-7 in 2-41080).
(c)	41	--	Agreement, dated April 3, 1972, between Entergy Services and Gulf United Nuclear Fuels Corporation (5(l)-3 in 2-46152).
(c)	42	--	Fuel Lease, dated as of December 22, 1988, between River Fuel Trust #1 and AP&L (B-1(b) to Rule 24 Certificate in 70-7571).
(c)	43	--	White Bluff Operating Agreement, dated June 27, 1977, among AP&L and Arkansas Electric Cooperative Corporation and City Water and Light Plant of the City of Jonesboro, Arkansas (B-2(a) to Rule 24 Certificate, dated June 30, 1977, in 70-6009).
(c)	44	--	White Bluff Ownership Agreement, dated June 27, 1977, among AP&L and Arkansas Electric Cooperative Corporation and City Water and Light Plant of the City of Jonesboro, Arkansas (B-1(a) to Rule 24 Certificate, dated June 30, 1977, in 70-6009).
(c)	45	--	Agreement, dated June 29, 1979, between AP&L and City of Conway, Arkansas (5(r)-3 in 2-66235).
(c)	46	--	Transmission Agreement, dated August 2, 1977, between AP&L and City Water and Light Plant of the City of Jonesboro, Arkansas (5(r)-3 in 2-60233).
(c)	47	--	Power Coordination, Interchange and Transmission Service Agreement, dated as of June 27, 1977, between Arkansas Electric Cooperative Corporation and AP&L (5(r)-4 in 2-60233).
(c)	48	--	Independence Steam Electric Station Operating Agreement, dated July 31, 1979, among AP&L and Arkansas Electric Cooperative Corporation and City Water and Light Plant of the City of Jonesboro, Arkansas and City of Conway, Arkansas (5(r)-6 in 2-66235).
(c)	49	--	Amendment, dated December 4, 1984, to the Independence Steam Electric Station Operating Agreement (10(c) 51 to Form 10-K for the fiscal year ended December 31, 1984, in 1-10764).
(c)	50	--	Independence Steam Electric Station Ownership Agreement, dated July 31, 1979, among AP&L and Arkansas Electric Cooperative Corporation and City Water and Light Plant of the City of Jonesboro, Arkansas and City of Conway, Arkansas (5(r)-7 in 2-66235).
(c)	51	--	Amendment, dated December 28, 1979, to the Independence Steam Electric Station Ownership Agreement (5(r)-7(a) in 2-66235).
(c)	52	--	Amendment, dated December 4, 1984, to the Independence Steam Electric Station Ownership Agreement (10(c) 54 to Form 10-K for the fiscal year ended December 31, 1984, in 1-10764).

(c)	53	--	Owner's Agreement, dated November 28, 1984, among AP&L, MP&L, other co-owners of the Independence Station (10(c) 55 to Form 10-K for the fiscal year ended December 31, 1984, in 1-10764).
(c)	54	--	Consent, Agreement and Assumption, dated December 4, 1984, among AP&L, MP&L, other co-owners of the Independence Station and United States Trust Company of New York, as Trustee (10(c) 56 to Form 10-K for the fiscal year ended December 31, 1984, in 1-10764).
(c)	55	--	Power Coordination, Interchange and Transmission Service Agreement, dated as of July 31, 1979, between AP&L and City Water and Light Plant of the City of Jonesboro, Arkansas (5(r)-8 in 2-66235).
(c)	56	--	Power Coordination, Interchange and Transmission Agreement, dated as of June 29, 1979, between City of Conway, Arkansas and AP&L (5(r)-9 in 2-66235).
(c)	57	--	Agreement, dated June 21, 1979, between AP&L and Reeves E. Ritchie ((10)(b)-90 to Form 10-K for the fiscal year ended December 31, 1980, in 1-10764).
(c)	58	--	Reallocation Agreement, dated as of July 28, 1981, among System Energy and certain other System companies (B-1(a) in 70-6624).
+(c)	59	--	Post-Retirement Plan (10(b) 55 to Form 10-K for the fiscal year ended December 31, 1983, in 1-10764).
(c)	60	--	Unit Power Sales Agreement, dated as of June 10, 1982, between System Energy and AP&L, LP&L, MP&L, and NOPSI (10(a) 39 to Form 10-K for the fiscal year ended December 31, 1982, in 1-3517).
(c)	61	--	First Amendment to Unit Power Sales Agreement, dated as of June 28, 1984, between System Energy, AP&L, LP&L, MP&L, and NOPSI (19 to Form 10-Q for the quarter ended September 30, 1984, in 1-3517).
(c)	62	--	Revised Unit Power Sales Agreement (10(ss) in 33-4033).
(c)	63	--	Contract For Disposal of Spent Nuclear Fuel and/or High-Level Radioactive Waste, dated June 30, 1983, among the DOE, System Fuels and AP&L (10(b)-57 to Form 10-K for the fiscal year ended December 31, 1983, in 1-10764).
(c)	64	--	Middle South Utilities, Inc. and Subsidiary Companies Intercompany Income Tax Allocation Agreement, dated April 28, 1988 (D-1 to Form U5S for the year ended December 31, 1987).
(c)	65	--	First Amendment, dated January 1, 1990, to the Middle South Utilities, Inc. and Subsidiary Companies Intercompany Income Tax Allocation Agreement (D-2 to Form U5S for the year ended December 31, 1989).
(c)	66	--	Second Amendment dated January 1, 1992, to the Entergy Corporation and Subsidiary Companies Intercompany Income Tax Allocation Agreement (D-3 to Form U5S for the year ended December 31, 1992).

(c)	67	--	Third Amendment dated January 1, 1994, to Entergy Corporation and Subsidiary Companies Intercompany Income Tax Allocation Agreement (D-3(a) to Form U5S for the year ended December 31, 1993).
(c)	68	--	Assignment of Coal Supply Agreement, dated December 1, 1987, between System Fuels and AP&L (B to Rule 24 letter filing, dated November 10, 1987, in 70-5964).
(c)	69	--	Coal Supply Agreement, dated December 22, 1976, between System Fuels and Antelope Coal Company (B-1 in 70-5964), as amended by First Amendment (A to Rule 24 Certificate in 70-5964); Second Amendment (A to Rule 24 letter filing, dated December 16, 1983, in 70-5964); and Third Amendment (A to Rule 24 letter filing, dated November 10, 1987 in 70-5964).
(c)	70	--	Operating Agreeme t between Entergy Operations and AP&L, dated as of June 6, 1990 (B-1(b) to Rule 24 (ertificate dated June 15, 1990, in 70-7679).
(c)	71	--	Guaranty Agreement between Entergy Corporation and AP&L, dated as of September 20, 1990 (B-1(a) to Rule 24 Certificate, dated September 27, 1990, in 70-7757).
(c)	72	--	Agreement for Purchase and Sale of Independence Unit 2 between AP&L and Entergy Power, dated as of August 28, 1990 (B-3(c) to Rule 24 Certificate, dated September 6, 1990, in 70-7684).
(c)	73	--	Agreement for Purchase and Sale of Ritchie Unit 2 between AP&L and Entergy Power, dated as of August 28, 1990 (B-4(d) to Rule 24 Certificate, dated September 6, 1990, in 70-7684).
(c)	74	--	Ritchie Steam Electric Station Unit No. 2 Operating Agreement between AP&L and Entergy Power, dated as of August 28, 1990 (B-5(a) to Rule 24 Certificate, dated September 6, 1990, in 70-7684).
(c)	75	--	Ritchie Steam Electric Station Unit No. 2 Ownership Agreement between AP&L and Entergy Power, dated as of August 28, 1990 (B-6(a) to Rule 24 Certificate, dated September 6, 1990, in 70-7684).
(c)	76	--	Power Coordination, Interchange and Transmission Service Agreement between Entergy Power and AP&L, dated as of August 28, 1990 (10(c)-71 to Form 10-K for the fiscal year ended December 31, 1990, in 1-10764).
*(c)	77	--	Executive Financial Counseling Program of Entergy Corporation and Subsidiaries (10(a)52 to Form 10-K for the year ended December 31, 1989, in 1-3517).
*(c)	78	--	Entergy Corporation Annual Incentive Plan (10(a)54 to Form 10-K for the year ended December 31, 1989, in 1-3517).
*(c)	79	--	Equity Ownership Plan of Entergy Corporation and Subsidiaries (A-4(a) to Rule 24 Certificate, dated May 24, 1991, in 70-7831).
*(c)	80	--	Agreement between Arkansas Power & Light Company and R. Drake Keith (10(c) 78 to Form 10-K for the year ended December 31, 1992 in 1-10764).

+(c)	81	--	Supplemental Retirement Plan (10(a)69 to Form 10-K for the year ended December 31, 1992 in 1-3517).
+(c)	82	--	Defined Contribution Restoration Plan of Entergy Corporation and Subsidiaries (10(a)53 to Form 10-K for the year ended December 31, 1989 in 1-3517).
+(c)	83	--	Amendment No. 1 to the Equity Ownership Plan of Entergy Corporation and Subsidiaries (10(a)71 to Form 10-K for the year ended December 31, 1992 in 1-3517).
+(c)	84	--	Executive Disability Plan of Entergy Corporation and Subsidiaries (10(a)72 to Form 10-K for the year ended December 31, 1992 in 1-3517).
+(c)	85	--	Executive Medical Plan of Entergy Corporation and Subsidiaries (10(a)73 to Form 10-K for the year ended December 31, 1992 in 1-3517).
+(c)	86	--	Stock Plan for Outside Directors of Entergy Corporation and Subsidiaries, as amended (10(a)74 to Form 10-K for the year ended December 31, 1992 in 1-3517).
+(c)	87	--	Summary Description of Private Ownership Vehicle Plan of Entergy Corporation and Subsidiaries (10(a)75 to Form 10-K for the year ended December 31, 1992 in 1-3517).
+(c)	88	--	Agreement between Entergy Corporation and Edwin Lupberger (10(a)-42 to Form 10-K for the year ended December 31, 1985 in 1-3517).
+(c)	89	--	Agreement between Entergy Corporation and Jerry D. Jackson (10(a)-68 to Form 10-K for the year ended December 31, 1992 in 1-3517).
+(c)	90	--	Agreement between Entergy Services and Gerald D. McInvale (10(a)-69 to Form 10-K for the year ended December 31, 1992 in 1-3517).
+(c)	91	--	Agreement between System Energy and Donald C. Hintz (10(b)-47 to Form 10-K for the year ended December 31, 1991 in 1-9067).
+(c)	92	--	Summary Description of Retired Outside Director Benefit Plan. (10(c) 90 to Form 10-K for the year ended December 31, 1992 in 1-10764).
+(c)	93	--	Amendment to Defined Contribution Restoration Plan of Entergy Corporation and Subsidiaries (10(a) 81 to Form 10-K for the year ended December 31, 1993 in 1-11299).
+(c)	94	--	System Executive Retirement Plan (10(a) 82 to Form 10-K for the year ended December 31, 1993 in 1-11299).
(c)	95	--	Loan Agreement dated June 15, 1993, between AP&L and Independence Country, Arkansas (B-1 (a) to Rule 24 Certificate dated July 9, 1993 in 70-8171).
(c)	96	--	Installment Sale Agreement dated January 1, 1991, between AP&L and Pope Country, Arkansas (B-1 (b) to Rule 24 Certificate dated January 24, 1991 in 70-7802).
(c)	97	--	Installment Sale Agreement dated November 1, 1990, between AP&L and Pope Country, Arkansas (B-1 (a) to Rule 24 Certificate dated November 30, 1990 in70-7802).

(c)	98	--	Installment Sale Agreement dated December 1, 1985, between AP&L and Pople Country, Arkansas (B-1(a) to Rule 24 Certificate dated December 19, 1985 in 70-7127).
(c)	99	--	Loan Agreement dated June 15, 1994, between AP&L and Jefferson County, Arkansas (B-1(a) to Rule 24 Certificate dated June 30, 1994 in 70-8405).
(c)	100	--	Loan Agreement dated June 15, 1994, between AP&L and Pope County, Arkansas (B-1(b) to Rule 24 Certificate in 70-8405).

GSU

(d)	1	--	Guaranty Agreement, dated July 1, 1976, between GSU and American Bank and Trust Company (C and D to Form 8-K, dated August 6, 1976 in 1-2703).
(d)	2	--	Lease of Railroad Equipment, dated as of December 1, 1981, between The Connecticut Bank and Trust Company as Lessor and GSU as Lessee and First Supplement, dated as of December 31, 1981, relating to 605 One Hundred-Ton Unit Train Steel Coal Porter Cars (4-12 to Form 10-K for the year ended December 31, 1981 in 1-2703).
(d)	3	--	Guaranty Agreement, dated August 1, 1992, between GSU and Hibernia National Bank, relating to Pollution Control Revenue Refunding Bonds of the Industrial Development Board of the Parish of Calcasieu, Inc. (Louisiana) (10-1 to Form 10-K for the year ended December 31, 1992 in 1-2703).
(d)	4	--	Guaranty Agreement, dated January 1, 1993, between GSU and Hancock Bank of Louisiana, relating to Pollution Control Revenue Refunding Bonds of the Parish of Pointe Coupee (Louisiana) (10-2 to Form 10-K for the year ended December 31, 1992 in 1-2703).
(d)	5	--	Deposit Agreement, dated as of December 1, 1983 between GSU, Morgan Guaranty Trust Co. as Depositary and the Holders of Despositary Receipts, relating to the Issue of 900,000 Depositary Preferred Shares, each representing 1/2 share of Adjustable Rate Cumulative Preferred Stock, Series E-$100 Par Value (4-17 to Form 10-K for the year ended December 31, 1983 in 1-2703).
(d)	6	--	Letter of Credit and Reimbursement Agreement, dated December 27, 1985, between GSU and Westpack Banking Corporation relating to Variable Rate Demand Pollution Control Revenue Bonds of the Parish of West Feliciana, State of Louisiana, Series 1985-D (4-26 to Form 10-K for the year ended December 31, 1985 in 1-2703) and Letter Agreement amending same dated October 20, 1992 (10-3 to Form 10-K for the year ended December 31, 1992 in 1-2703)
(d)	7	--	Reimbursement and Loan Agreement, dated as of April 23, 1986, by and between GSU and The Long-Term Credit Bank of Japan, Ltd., relating to Multiple Rate Demand Pollution Control Revenue Bonds of the Parish of West Feliciana, State of Louisiana, Series 1985 (4-26 to Form 10-K, for the year ended December 31, 1986 in 1-2703) and Letter Agreement amending same, dated February 19, 1993 (10 to Form 10-K for the year ended December 31, 1992 in 1-2703).
(d)	8	--	Agreement effective February 1, 1964, between Sabine River Authority, State of Louisiana, and Sabine River Authority of Texas, and GSU, Central Louisiana Electric Company, Inc., and Louisiana Power & Light Company, as supplemented (B to Form 8-K,

dated May 6, 1964, A to Form 8-K, dated October 5, 1967, A to Form 8-K, dated May 5, 1969, and A to Form 8-K, dated December 1, 1969, in 1-2708).

(d) 9 -- Joint Ownership Participation and Operating Agreement regarding River Bend Unit 1 Nuclear Plant, dated August 20, 1979, between GSU, Cajun, and SRG&T; Power Interconnection Agreement with Cajun, dated June 26, 1978, and approved by the REA on August 16, 1979, between GSU and Cajun; and Letter Agreement regarding CEPCO buybacks, dated August 28, 1979, between GSU and Cajun (2, 3, and 4, respectively, to Form 8-K, dated September 7, 1979, in 1-2703).

(d) 10 -- Ground Lease, dated August 15, 1980, between Statmont Associates Limited Partnership (Statmont) and GSU, as amended (3 to Form 8-K, dated August 19, 1980, and A-3-b to Form 10-Q for the quarter ended September 30, 1983 in 1-2703).

(d) 11 -- Lease and Sublease Agreement, dated August 15, 1980, between Statmont and GSU, as amended (4 to Form 8-K, dated August 19, 1980, and A-3-c to Form 10-Q for the quarter ended September 30, 1983 in 1-2703).

(d) 12 -- Lease Agreement, dated September 18, 1980, between BLC Corporation and GSU (1 to Form 8-K, dated October 6, 1980 in 1-2703).

(d) 13 -- Joint Ownership Participation and Operating Agreement for Big Cajun, between GSU, Cajun Electric Power Cooperative, Inc., and Sam Rayburn G&T, Inc, dated November 14, 1980 (6 to Form 8-K, dated January 29, 1981 in 1-2703); Amendment No. 1, dated December 12, 1980 (7 to Form 8-K, dated January 29, 1981 in 1-2703); Amendment No. 2, dated December 29, 1980 (8 to Form 8-K, dated January 29, 1981 in 1-2703).

(d) 14 -- Agreement of Joint Ownership Participation between SRMPA, SRG&T and GSU, dated June 6, 1980, for Nelson Station, Coal Unit #6, as amended (8 to Form 8-K, dated June 11, 1980, A-2-b to Form 10-Q For the quarter ended June 30, 1982; and 10-1 to Form 8-K, dated February 19, 1988 in 1-2703).

(d) 15 -- Agreements between Southern Company and GSU, dated February 25, 1982, which cover the construction of a 140-mile transmission line to connect the two systems, purchase of power and use of transmission facilities (10-31 to Form 10-K, for the year ended December 31, 1981 in 1-2703).

+(d) 16 -- Executive Income Security Plan, effective October 1, 1980, as amended, continued and completely restated effective as of March 1, 1991 (10-2 to Form 10-K for the year ended December 31, 1991 in 1-2703).

(d) 17 -- Joint Ownership Participation Agreement for Big Cajun between GSU, Cajun, and SRG&T, dated November 14, 1980 (6 to Form 8-K, dated January 29, 1981 in 1-2703).

(d) 18 -- Amendment No. 1 to the Joint Ownership Participation Agreement for Big Cajun, between GSU, Cajun, and SRG&T, dated December 12, 1980 (7 to Form 8-K, dated January 29, 1981 in 1-2703).

(d) 19 -- Amendment No. 2 to the Joint Ownership Participation Agreement for Big Cajun, between GSU, Cajun, and SRG&T, dated December 29, 1980 (8 to Form 8-K, dated January 29, 1981 in 1-2703).

(d)	20	--	Transmission Facilities Agreement between GSU and Mississippi Power Company, dated February 28, 1982, and Amendment, dated May 12, 1982 (A-2-c to Form 10-Q for the quarter ended March 31, 1982 in 1-2703) and Amendment, dated December 6, 1983 (10-43 to Form 10-K, for the year ended December 31, 1983 in 1-2703).
(d)	21	--	Lease Agreement dated as of June 29, 1983, between GSU and City National Bank of Baton Rouge, as Owner Trustee, in connection with the leasing of a Simulator and Training Center for River Bend Unit 1 (A-2-a to Form 10-Q for the quarter ended June 30, 1983 in 1-2703) and Amendment, dated December 14, 1984 (10-55 to Form 10-K, for the year ended December 31, 1984 in 1-2703).
(d)	22	--	Participation Agreement, dated as of June 29, 1983, among GSU, City National Bank of Baton Rouge, PruFunding, Inc. Bank of the Southwest National Association, Houston and Bankers Life Company, in connection with the leasing of a Simulator and Training Center of River Bend Unit 1 (A-2-b to Form 10-Q for the quarter ended June 30, 1983 in 1-2703).
(d)	23	--	Tax Indemnity Agreement, dated as of June 29, 1983, between GSU and Prufunding, Inc., in connection with the leasing of a Simulator and Training Center for River Bend Unit 1 (A-2-c to Form 10-Q for the quarter ended June 30, 1993 in 1-2703).
(d)	24	--	Agreement to Lease, dated as of August 28, 1985, among GSU, City National Bank of Baton Rouge, as Owner Trustee, and Prudential Interfunding Corp., as Trustor, in connection with the leasing of improvement to a Simulator and Training Facility for River Bend Unit 1 (10-69 to Form 10-K, for the year ended December 31, 1985 in 1-2703).
(d)	25	--	First Amended Power Sales Agreement, dated December 1, 1985 between Sabine River Authority, State of Louisiana, and Sabine River Authority, State of Texas, and GSU, Central Louisiana Electric Co., Inc., and Louisiana Power and Light Company (10-72 to Form 10-K for the year ended December 31, 1985 in 1-2703).
+(d)	26	--	Deferred Compensation Plan for Directors of GSU and Varibus Corporation, as amended January 8, 1987, and effective January 1, 1987 (10-77 to Form 10-K for the year ended December 31, 1986 in 1-2703). Amendment dated December 4, 1991 (10-3 to Amendment No. 8 in Registration No. 2-76551).
+(d)	27	--	Trust Agreement for Deferred Payments to be made by GSU pursuant to the Executive Income Security Plan, by and between GSU and Bankers Trust Company, effective November 1, 1986 (10-78 to Form 10-K for the year ended December 31, 1986 in 1-2703).
+(d)	28	--	Trust Agreement for Deferred Installments under GSU's Management Incentive Compensation Plan and Administrative Guidelines by and between GSU and Bankers Trust Company, effective June 1, 1986 (10-79 to Form 10-K for the year ended December 31, 1986 in 1-2703).
+(d)	29	--	Nonqualified Deferred Compensation Plan for Officers, Nonemployee Directors and Designated Key Employees, effective December 1, 1985, as amended, continued and completely restated effective as of March 1, 1991 (10-3 to Amendment No. 8 in Registration No. 2-76551).
+(d)	30	--	Trust Agreement for GSU's Nonqualified Directors and Designated Key Employees by and between GSU and First City Bank, Texas-Beaumont, N.A. (now Texas Commerce Bank),

			effective July 1, 1991 (10-4 to Form 10-K for the year ended December 31, 1992 in 1-2703).
(d)	31	--	Lease Agreement, dated as of June 29, 1987, among GSC&T, Inc., and GSU related to the leaseback of the Lewis Creek generating station (10-83 to Form 10-K for the year ended December 31, 1988 in 1-2703).
(d)	32	--	Nuclear Fuel Lease Agreement between GSU and River Bend Fuel Services, Inc. to lease the fuel for River Bend Unit 1, dated February 7, 1989 (10-64 to Form 10-K for the year ended December 31, 1988 in 1-2703).
(d)	33	--	Trust and Investment Management Agreement between GSU and Morgan Guaranty and Trust Company of New York with respect to decommissioning funds authorized to be collected by GSU, dated March 15, 1989 (10-66 to Form 10-K for the year ended December 31, 1988 in 1-2703).
*(d)	34	--	Credit Agreement, dated as of December 29, 1993, among River Bend Fuel Services, Inc. and Certain Commercial Lending Institutions and CIBC Inc. as Agent for the Lenders.
(d)	35	--	Partnership Agreement by and among Conoco Inc., and GSU, CITGO Petroleum Corporation and Vista Chemical Company, dated April 28, 1988 (10-67 to Form 10-K for the year ended December 31, 1988 in 1-2703).
+(d)	36	--	Gulf States Utilities Company Executive Continuity Plan, dated January 18, 1991 (10-6 to Form 10-K for the year ended December 31, 1990 in 1-2703).
+(d)	37	--	Trust Agreement for GSU's Executive Continuity Plan, by and between GSU and First City Bank, Texas-Beaumont, N.A. (now Texas Commerce Bank), effective May 20, 1991 (10-5 to Form 10-K for the year ended December 31, 1992 in 1-2703).
+(d)	38	--	Gulf States Utilities Board of Directors' Retirement Plan, dated February 15, 1991 (10-8 to Form 10-K for the year ended December 31, 1990 in 1-2703).
+(d)	39	--	Gulf States Utilities Company Employees' Trustee Retirement Plan effective July 1, 1955 as amended, continued and completely restated effective January 1, 1989; and Amendment No.1 effective January 1, 1993 (10-6 to Form 10-K for the year ended December 31, 1992 in 1-2703).
(d)	40	--	Agreement and Plan of Reorganization, dated June 5, 1992, between GSU and Entergy Corporation (2 to Form 8-K, dated June 8, 1992 in 1-2703).
+(d)	41	--	Gulf States Utilities Company Employee Stock Ownership Plan, as amended, continued, and completely restated effective January 1, 1984, and January 1, 1985 (A to Form 11-K, dated December 31, 1985 in 1-2703).
+(d)	42	--	Trust Agreement under the Gulf States Utilities Company Employee Stock Ownership Plan, dated December 30, 1976, between GSU and the Louisiana National Bank, as Trustee (2-A to Registration No. 2-62395).
+(d)	43	--	Letter Agreement dated September 7, 1977 between GSU and the Trustee, delegating certain of the Trustee's functions to the ESOP Committee (2-B to Registration Statement No. 2-62395).

+(d)	44	--	Gulf States Utilities Company Employees Thrift Plan as amended, continued and completely restated effective as of January 1, 1992 (28-1 to Amendment No. 8 to Registration No. 2-76551).
+(d)	45	--	Restatement of Trust Agreement under the Gulf States Utilities Company Employees Thrift Plan, reflecting changes made through January 1, 1989, between GSU and First City Bank, Texas-Beaumont, N.A., (now Texas Commerce Bank), as Trustee (2-A to Form 8-K dated October 20, 1989 in 1-2703).
(d)	46	--	Operating Agreement between Entergy Operations and GSU, dated as of December 31, 1993 (B-2(f) to Rule 24 Certificate in 70-8059).
(d)	47	--	Guarantee Agreement between Entergy Corporation and GSU, dated as of December 31, 1993 (B-5(a) to Rule 24 Certificate in 70-8059).
(d)	48	--	Service Agreement with Entergy Services, dated as of December 31, 1993 (B-6(c) to Rule 24 Certificate in 70-8059).
+(d)	49	--	Amendment to Employment Agreement between J. L. Donnelly and GSU, dated December 22, 1993 (10(d) 57 to Form 10-K for the year ended December 31, 1993 in 1-2703).
(d)	50	--	Amendment to Letter of Credit and Reimbursement Agreement between GSU and Westpac Banking Corporation (10(d) 58 to Form 10-K for the year ended December 31, 1993 in 1-2703).
(d)	51	--	Third Amendment, dated January 1, 1994, to Entergy Corporation and Subsidiary Companies Intercompany Income Tax Allocation Agreement (D-3(a) to Form U5S for the year ended December 31, 1993).
(d)	52	--	Refunding Agreement between GSU and West Feliciana Parish (dated December 20, 1994 (B-12(a) to Rule 24 Certificate dated December 30, 1994 in 70-8375).
LP&L			
(e)	1	--	Agreement, dated April 23, 1982, among LP&L and certain other System companies, relating to System Planning and Development and Intra-System Transactions (10(a) 1 to Form 10-K for the fiscal year ended December 31, 1982, in 1-3517).
(e)	2	--	Middle South Utilities System Agency Agreement, dated December 11, 1970 (5(a)-2 in 2-41080).
(e)	3	--	Amendment, dated as of February 10, 1971, to Middle South Utilities System Agency Agreement, dated December 11, 1970 (5(a)-4 in 2-41080).
(e)	4	--	Amendment, dated May 12, 1988, to Middle South Utilities System Agency Agreement, dated December 11, 1970 (5(a) 4 in 2-41080).
(e)	5	--	Middle South Utilities System Agency Coordination Agreement, dated December 11, 1970 (5(a)-3 in 2-41080).
(e)	6	--	Service Agreement with Entergy Services, dated as of April 1, 1963 (5(a)-5 in 2-42523).

(c)	7	--	Amendment, dated as of January 1, 1972, to Service Agreement with Entergy Services (4(a)-6 in 2-45916).
(c)	8	--	Amendment, dated as of April 27, 1984, to Service Agreement with Entergy Services (10(a) 7 to Form 10-K for the fiscal year ended December 31, 1984, in 1-3517).
(c)	9	--	Amendment, dated as of August 1, 1988, to Service Agreement with Entergy Services (10(d)-8 to Form 10-K for the fiscal year ended December 31, 1988, in 1-8474).
(c)	10	--	Amendment, dated January 1, 1991, to Service Agreement with Entergy Services (10(d)-9 to Form 10-K for the fiscal year ended December 31, 1990, in 1-8474).
*(c)	11	--	Amendment, dated January 1, 1992, to Service Agreement with Entergy Services.
(c)	12	--	Availability Agreement, dated June 21, 1974, among System Energy and certain other System companies (B to Rule 24 Certificate, dated June 24, 1974, in 70-5399).
(c)	13	--	First Amendment to Availability Agreement, dated as of June 30, 1977 (B to Rule 24 Certificate, dated June 30, 1977, in 70-5399).
(c)	14	--	Second Amendment to Availability Agreement, dated as of June 15, 1981 (E to Rule 24 Certificate, dated July 1, 1981, in 70-6592).
(c)	15	--	Third Amendment to Availability Agreement, dated as of June 28, 1984 (B-13(a) to Rule 24 Certificate, dated July 6, 1984, in 70-6985).
(c)	16	--	Fourth Amendment to Availability Agreement, dated as of June 1, 1989 (A to Rule 24 Certificate, dated June 8, 1989, in 70-5399).
(c)	17	--	Fourteenth Assignment of Availability Agreement, Consent and Agreement, dated as of June 15, 1985, with Deposit Guaranty National Bank, United States Trust Company of New York and Malcolm J. Hood, as Trustees (B-3(b) to Rule 24 Certificate, dated July 31, 1985, in 70-7026).
(c)	18	--	Fifteenth Assignment of Availability Agreement, Consent and Agreement, dated as of May 1, 1986, with United States Trust Company of New York, Malcolm J. Hood, and Deposit Guaranty National Bank, as Trustees (B-3(b) to Rule 24 Certificate, dated June 5, 1986, in 70-7158).
(c)	19	--	Sixteenth Assignment of Availability Agreement, Consent and Agreement, dated as of May 1, 1986, with United States Trust Company of New York and Malcolm J. Hood, as Trustees (C to Rule 24 Certificate, dated June 4, 1986, in 70-7123).
(c)	20	--	Eighteenth Assignment of Availability Agreement, Consent and Agreement, dated as of September 1, 1986, with United States Trust Company of New York and Gerard F. Ganey, as Trustees (C-2 to Rule 24 Certificate, dated October 1, 1986, in 70-7272).
(c)	21	--	Nineteenth Assignment of Availability Agreement, Consent and Agreement, dated as of September 1, 1986, with United States Trust Company of New York and Gerard F. Ganey, as Trustees (C-3 to Rule 24 Certificate, dated October 1, 1986, in 70-7272).

(c)	22	--	Twenty-fourth Assignment of Availability Agreement, Consent and Agreement, dated as of July 1, 1992, with United States Trust Company of New York and Gerard F. Ganey, as Trustees (B-2(b) to Rule 24 Certificate, dated July 14, 1992, in 70-7946).
(c)	23	--	Twenty-fifth Assignment of Availability Agreement, Consent and Agreement, dated as of October 1, 1992, with United States Trust Company of New York and Gerard F. Ganey, as Trustees (B-2(b) to Rule 24 Certificate, dated November 2, 1992, in 70-7946).
(c)	24	--	Twenty-sixth Assignment of Availability Agreement, Consent and Agreement, dated as of October 1, 1992, with United States Trust Company of New York and Gerard F. Ganey, as Trustees (B-2(c) to Rule 24 Certificate, dated November 2, 1992, in 70-7946).
(c)	25	--	Twenty-seventh Assignment of Availability Agreement, Consent and Agreement, dated as of April 1, 1993, with United States Trust Company of New York and Gerard F. Ganey as Trustees (B-2(d) to Rule 24 Certificate dated May 4, 1993 in 70-7946).
(c)	26	--	Twenty-eighth Assignment of Availability Agreement, Consent and Agreement, dated as of December 17,1993, with Chemical Bank, as Agent (B-2(a) to Rule 24 Certificate dated December 22, 1993 in 70-7561).
(c)	27	--	Twenty-ninth Assignment of Availability Agreement, Consent and Agreement, dated as of April 1, 1994, with United States Trust Company of New York and Gerard F. Ganey, as Trustees, (B-2(f) to Rule 24 Certificate dated May 6, 1994 in 70-7946).
(c)	28	--	Fuel Lease, dated as of January 31, 1989, between River Fuel Company #2, Inc., and LP&L (B-1(b) to Rule 24 Certificate in 70-7580).
(c)	29	--	Reallocation Agreement, dated as of July 28, 1981, among System Energy and certain other System companies (B-1(a) in 70-6624).
(c)	30	--	Compromise and Settlement Agreement, dated June 4, 1982, between Texaco, Inc. and LP&L (28(a) to Form 8-K, dated June 4, 1982, in 1-8474).
+(c)	31	--	Post-Retirement Plan (10(c)23 to Form 10-K for the year ended December 31, 1983, in 1-8474).
(c)	32	--	Unit Power Sales Agreement, dated as of June 10, 1982, between System Energy and AP&L, LP&L, MP&L and NOPSI (10(a) 39 to Form 10-K for the fiscal year ended December 31, 1982, in 1-3517).
(c)	33	--	First Amendment to the Unit Power Sales Agreement, dated as of June 28, 1984, between System Energy and AP&L, LP&L, MP&L and NOPSI (19 to Form 10-Q for the quarter ended September 30, 1984, in 1-3517)
(c)	34	--	Revised Unit Power Sales Agreement (10(ss) in 33-4033).
(c)	35	--	Middle South Utilities, Inc. and Subsidiary Companies Intercompany Tax Allocation Agreement, dated April 28, 1988 (D-1 to Form U5S for the year ended December 31, 1987)

(c)	36	--	First Amendment, dated January 1, 1990, to the Middle South Utilities, Inc. and Subsidiary Companies Intercompany Income Tax Allocation Agreement, dated January 1, 1990 (D-2 to Form U5S for the year ended December 31, 1989).
(c)	37	--	Second Amendment dated January 1, 1992, to the Entergy Corporation and Subsidiary Companies Intercompany Income Tax Allocation Agreement (D-3 to Form U5S for the year ended December 31, 1992).
(c)	38	--	Third Amendment dated January 1, 1994 to Entergy Corporation and Subsidiary Companies Intercompany Income Tax Allocation Agreement (D-3(a) to Form U5S for the year ended December 31, 1993).
(c)	39	--	Contract for Disposal of Spent Nuclear Fuel and/or High-Level Radioactive Waste, dated February 2, 1984, among DOE, System Fuels and LP&L (10(d)33 to Form 10-K for the fiscal year ended December 31, 1984, in 1-8474).
(c)	40	--	Operating Agreement between Entergy Operations and LP&L, dated as of June 6, 1990 (B-2(c) to Rule 24 Certificate, dated June 15, 1990, in 70-7679).
(c)	41	--	Guarantee Agreement between Entergy Corporation and LP&L, dated as of September 20, 1990 (B-2(a), to Rule 24 Certificate, dated September 27, 1990, in 70-7757).
+(c)	42	--	Executive Financial Counseling Program of Entergy Corporation and Subsidiaries (10(a) 52 to Form 10-K for the year ended December 31, 1989, in 1-3517).
+(c)	43	--	Entergy Corporation Annual Incentive Plan (10(a) 54 to Form 10-K for the year ended December 31, 1989, in 1-3517).
+(c)	44	--	Equity Ownership Plan of Entergy Corporation and Subsidiaries (A-4(a) to Rule 24 Certificate, dated May 24, 1991, in 70-7831).
+(c)	45	--	Supplemental Retirement Plan (10(a) 69 to Form 10-K for the year ended December 31, 1992 in 1-3517).
+(c)	46	--	Defined Contribution Restoration Plan of Entergy Corporation and Subsidiaries (10(a) 53 to Form 10-K for the year ended December 31, 1989 in 1-3517).
+(c)	47	--	Amendment No. 1 to the Equity Ownership Plan of Entergy Corporation and Subsidiaries (10(a) 71 to Form 10-K for the year ended December 31, 1992 in 1-3517).
+(c)	48	--	Executive Disability Plan of Entergy Corporation and Subsidiaries (10(a) 72 to Form 10-K for the year ended December 31, 1992 in 1-3517).
+(c)	49	--	Executive Medical Plan of Entergy Corporation and Subsidiaries (10(a) 73 to Form 10-K for the year ended December 31, 1992 in 1-3517).
+(c)	50	--	Stock Plan for Outside Directors of Entergy Corporation and Subsidiaries (10(a) 74 to Form 10-K for the year ended December 31, 1992 in 1-3517).
+(c)	51	--	Summary Description of Private Ownership Vehicle Plan of Entergy Corporation and Subsidiaries (10(a) 75 to Form 10-K for the year ended December 31, 1992 in 1-3517).

+(c)	52	--	Agreement between Entergy Corporation and Edwin Lupberger (10(a) 42 to Form 10-K for the year ended December 31, 1985 in 1-3517).
+(c)	53	--	Agreement between Entergy Corporation and Jerry D. Jackson (10(a) 68 to Form 10-K for the year ended December 31, 1992 in 1-3517).
+(c)	54	--	Agreement between Entergy Services and Gerald D. McInvale (10(a) 69 to Form 10-K for the year ended December 31, 1992 in 1-3517).
+(c)	55	--	Agreement between System Energy and Donald C. Hintz (10(b) 47 to Form 10-K for the year ended December 31, 1991 in 1-9067).
+(c)	56	--	Summary Description of Retired Outside Director Benefit Plan (10(c)90 to Form 10-K for the year ended December 31, 1992 in 1-10764).
+(c)	57	--	Amendment to Defined Contribution Restoration Plan of Entergy Corporation and Subsidiaries (10(a) 81 to Form 10-K for the year ended December 31, 1993 in 1-11299).
+(c)	58	--	System Executive Retirement Plan (10(a) 82 to Form 10-K for the year ended December 31, 1993 in 1-11299).
(c)	59	--	Installment Sale Agreement, dated July 20, 1994, between LP&L and St. Charles Parish, Louisiana (B-6(e) to Rule 24 Certificate dated August 1, 1994 in 70-7822).
MP&L			
(f)	1	--	Agreement dated April 23, 1982, among MP&L and certain other System companies, relating to System Planning and Development and Intra-System Transactions (10(a) 1 to Form 10-K for the fiscal year ended December 31, 1982, in 1-3517).
(f)	2	--	Middle South Utilities System Agency Agreement, dated December 11, 1970 (5(a)-2 in 2-41080).
(f)	3	--	Amendment, dated February 10, 1971, to Middle South Utilities System Agency Agreement, dated December 11, 1970 (5(a) 4 in 2-41080).
(f)	4	--	Amendment, dated May 12, 1988, to Middle South Utilities System Agency Agreement, dated December 11, 1970 (5(a) 4 in 2-41080).
(f)	5	--	Middle South Utilities System Agency Coordination Agreement, dated December 11, 1970 (5(a)-3 in 2-41080).
(f)	6	--	Service Agreement with Entergy Services, dated as of April 1, 1963 (D in 37-63).
(f)	7	--	Amendment, dated January 1, 1972, to Service Agreement with Entergy Services (A to Notice, dated October 14, 1971, in 37-63).
(f)	8	--	Amendment, dated April 27, 1984, to Service Agreement with Entergy Services (10(a) 7 to Form 10-K for the fiscal year ended December 31, 1984, in 1-3517).
(f)	9	--	Amendment, dated as of August 1, 1988, to Service Agreement with Entergy Services (10(e) 8 to Form 10-K for the fiscal year ended December 31, 1988, in 0-320).

(f)	10	--	Amendment, dated January 1, 1991, to Service Agreement with Entergy Services (10(c) 9 to Form 10-K for the fiscal year ended December 31, 1990, in 0-320).
*(f)	11	--	Amendment, dated January 1, 1992, to Service Agreement with Entergy Services.
(f)	12	--	Availability Agreement, dated June 21, 1974, among System Energy and certain other System companies (B to Rule 24 Certificate, dated June 24, 1974, in 70-5399).
(f)	13	--	First Amendment to Availability Agreement, dated as of June 30, 1977 (B to Rule 24 Certificate, dated June 24, 1977, in 70-5399).
(f)	14	--	Second Amendment to Availability Agreement, dated as of June 15, 1981 (E to Rule 24 Certificate, dated July 1, 1981, in 70-6592).
(f)	15	--	Third Amendment to Availability Agreement, dated as of June 28, 1984 (B-13(a) to Rule 24 Certificate, dated July 6, 1984, in 70-6985).
(f)	16	--	Fourth Amendment to Availability Agreement, dated as of June 1, 1989 (A to Rule 24 Certificate, dated June 8, 1989, in 70-5399).
(f)	17	--	Fourteenth Assignment of Availability Agreement, Consent and Agreement, dated as of June 15, 1985, with Deposit Guaranty National Bank, United States Trust Company of New York and Malcolm J. Hood, as Trustees (B-3(b) to Rule 24 Certificate, dated July 31, 1985, in 70-7026).
(f)	18	--	Fifteenth Assignment of Availability Agreement, Consent and Agreement, dated as of May 1, 1986, with United States Trust Company of New York, Malcolm J. Hood, and Deposit Guaranty National Bank, as Trustees (B-3(b) to Rule 24 Certificate, dated June 5, 1986, in 70-7158).
(f)	19	--	Sixteenth Assignment of Availability Agreement, Consent and Agreement, dated as of May 1, 1986, with United States Trust Company of New York and Malcolm J. Hood, as Trustees (C to Rule 24 Certificate, dated June 4, 1986, in 70-7123).
(f)	20	--	Eighteenth Assignment of Availability Agreement, Consent and Agreement, dated as of September 1, 1986, with United States Trust Company of New York and Gerard F. Ganey, as Trustees (C-2 to Rule 24 Certificate, dated October 1, 1986, in 70-7272).
(f)	21	--	Nineteenth Assignment of Availability Agreement, Consent and Agreement, dated as of September 1, 1986, with United States Trust Company of New York and Gerard F. Ganey, as Trustees (C-3 to Rule 24 Certificate, dated October 1, 1986, in 70-7272).
(f)	22	--	Twenty-fourth Assignment of Availability Agreement, Consent and Agreement, dated as of July 1, 1992, with United States Trust Company of New York and Gerard F. Ganey, as Trustees (B-2(b) to Rule 24 Certificate, dated July 14, 1992, in 70-7946).
(f)	23	--	Twenty-fifth Assignment of Availability Agreement, Consent and Agreement, dated as of October 1, 1992, with United States Trust Company of New York and Gerard F. Ganey, as Trustees (B-2(b) to Rule 24 Certificate, dated November 2, 1992, in 70-7946).

(f)	24	--	Twenty-sixth Assignment of Availability Agreement, Consent and Agreement, dated as of October 1, 1992, with United States Trust Company of New York and Gerard F. Ganey, as Trustees (B-2(c) to Rule 24 Certificate, dated November 2, 1992, in 70-7946).
(f)	25	--	Twenty-seventh Assignment of Availability Agreement, Consent and Agreement, dated as of April 1, 1993, with United States Trust Company of New York and Gerard F. Ganey as Trustees (B-2(d) to Rule 24 Certificate dated May 4, 1993 in 70-7946).
(f)	26	--	Twenty-eighth Assignment of Availability Agreement, Consent and Agreement, dated as of December 17, 1993, with Chemical Bank, as Agent (B-2(a) to Rule 24 Certificate dated December 22, 1993 in 70-7561).
(f)	27	--	Twenty-ninth Assignment of Availability Agreement, Consent and Agreement, dated as of April 1, 1994, with United States Trust Company of New York and Gerard F. Ganey as Trustees (B-2(f) to Rule 24 Certificate dated May 6, 1994, in 70-7946).
(f)	28	--	Installment Sale Agreement, dated as of June 1, 1974, between MP&L and Washington County, Mississippi (B-2(a) to Rule 24 Certificate, dated August 1, 1974, in 70-5504).
(f)	29	--	Installment Sale Agreement, dated as of July 1, 1982, between MP&L and Independence County, Arkansas, (B-1(c) to Rule 24 Certificate dated July 21, 1982, in 70-6672).
(f)	30	--	Installment Sale Agreement, dated as of December 1, 1982, between MP&L and Independence County, Arkansas, (B-1(d) to Rule 24 Certificate dated December 7, 1982, in 70-6672).
(f)	31	--	Amended and Restated Installment Sale Agreement, dated as of April 1, 1994, between MP&L and Warren County, Mississippi, (B-6(a) to Rule 24 Certificate dated May 4, 1994, in 70-7914).
(f)	32	--	Amended and Restated Installment Sale Agreement, dated as of April 1, 1994, between MP&L and Washington County, Mississippi, (B-6(b) to Rule 24 Certificate dated May 4, 1994, in 70-7914).
(f)	33	--	Substitute Power Agreement, dated as of May 1, 1980, among MP&L, System Energy and SMEPA (B-3(a) in 70-6337).
(f)	34	--	Amendment, dated December 4, 1984, to the Independence Steam Electric Station Operating Agreement (10(c) 51 to Form 10-K for the fiscal year ended December 31, 1984, in 0-375).
(f)	35	--	Amendment, dated December 4, 1984, to the Independence Steam Electric Station Ownership Agreement (10(c) 54 to Form 10-K for the fiscal year ended December 31, 1984, in 0-375).
(f)	36	--	Owners Agreement dated November 28, 1984, among AP&L, MP&L and other co-owners of the Independence Station (10(c) 55 to Form 10-K for the fiscal year ended December 31, 1984, in 0-375).
(f)	37	--	Consent, Agreement and Assumption, dated December 4, 1984, among AP&L, MP&L, other co-owners of the Independence Station and United States Trust Company of New

			York, as Trustee (10(c) 56 to Form 10-K for the fiscal year ended December 31, 1984, in 0-375).
(f)	38	--	Reallocation Agreement, dated as of July 28, 1981, among System Energy and certain other System companies (B-1(a) in 70-6624).
+(f)	39	--	Post-Retirement Plan (10(d) 24 to Form 10-K for the fiscal year ended December 31, 1983, in 0-320).
(f)	40	--	Unit Power Sales Agreement, dated as of June 10, 1982, between System Energy and AP&L, LP&L, MP&L, and NOPSI (10(a) 39 to Form 10-K for the fiscal year ended December 31, 1982, in 1-3517).
(f)	41	--	First Amendment to the Unit Power Sales Agreement, dated as of June 28, 1984, between System Energy and AP&L, LP&L, MP&L, and NOPSI (19 to Form 10-Q for the quarter ended September 30, 1984, in 1-3517).
(f)	42	--	Revised Unit Power Sales Agreement (10(ss) in 33-4033).
(f)	43	--	Sales Agreement, dated as of June 21, 1974, between System Energy and MP&L (D to Rule 24 Certificate, dated June 26, 1974, in 70-5399).
(f)	44	--	Service Agreement, dated as of June 21, 1974, between System Energy and MP&L (E to Rule 24 Certificate, dated June 26, 1974, in 70-5399).
(f)	45	--	Partial Termination Agreement, dated as of December 1, 1986, between System Energy and MP&L (A-2 to Rule 24 Certificate dated January 8, 1987, in 70-5399).
(f)	46	--	Middle South Utilities, Inc. and Subsidiary Companies Intercompany Income Tax Allocation Agreement, dated April 28, 1988 (D-1 to Form U5S for the year ended December 31, 1987).
(f)	47	--	First Amendment dated January 1, 1990 to the Middle South Utilities Inc. and Subsidiary Companies Intercompany Tax Allocation Agreement (D-2 to Form U5S for the year ended December 31, 1989).
(f)	48	--	Second Amendment dated January 1, 1992, to the Entergy Corporation and Subsidiary Companies Intercompany Income Tax Allocation Agreement (D-3 to Form U5S for the year ended December 31, 1992).
(f)	49	--	Third Amendment dated January 1, 1994 to Entergy Corporation and Subsidiary Companies Intercompany Income Tax Allocation Agreement (D-3(a) to Form U5S for the year ended December 31, 1993).
+(f)	50	--	Executive Financial Counseling Program of Entergy Corporation and Subsidiaries (10(a) 52 to Form 10-K for the year ended December 31, 1989, in 1-3517).
+(f)	51	--	Entergy Corporation Annual Incentive Plan (10(a) 54 to Form 10-K for the year ended December 31, 1989, in 1-3517).
+(f)	52	--	Equity Ownership Plan of Entergy Corporation and Subsidiaries (A-4(a) to Rule 24 Certificate, dated May 24, 1991, in 70-7831).

+(f)	53	--	Supplemental Retirement Plan (10(a)69 to Form 10-K for the year ended December 31, 1992 in 1-3517).
+(f)	54	--	Defined Contribution Restoration Plan of Entergy Corporation and Subsidiaries (10(a)53 to Form 10-K for the year ended December 31, 1989 in 1-3517).
+(f)	55	--	Amendment No. 1 to the Equity Ownership Plan of Entergy Corporation and Subsidiaries (10(a)71 to Form 10-K for the year ended December 31, 1992 in 1-3517).
+(f)	56	--	Executive Disability Plan of Entergy Corporation and Subsidiaries (10(a)72 to Form 10-K for the year ended December 31, 1992 in 1-3517).
+(f)	57	--	Executive Medical Plan of Entergy Corporation and Subsidiaries (10(a)73 to Form 10-K for the year ended December 31, 1992 in 1-3517).
+(f)	58	--	Stock Plan for Outside Directors of Entergy Corporation and Subsidiaries, as amended (10(a)74 to Form 10-K for the year ended December 31, 1992 in 1-3517).
+(f)	59	--	Summary Description of Private Ownership Vehicle Plan of Entergy Corporation and Subsidiaries (10(a)75 to Form 10-K for the year ended December 31, 1992 in 1-3517).
+(f)	60	--	Agreement between Entergy Corporation and Edwin Lupberger (10(a)-42 to Form 10-K for the year ended December 31, 1985 in 1-3517).
+(f)	61	--	Agreement between Entergy Corporation and Jerry D. Jackson (10(a)-68 to Form 10-K for the year ended December 31, 1992 in 1-3517).
+(f)	62	--	Agreement between Entergy Services and Gerald D. McInvale (10(a)-69 to Form 10-K for the year ended December 31, 1992 in 1-3517).
+(f)	63	--	Agreement between System Energy and Donald C. Hintz (10(b)-47 to Form 10-K for the year ended December 31, 1991 in 1-9067).
+(f)	64	--	Summary Description of Retired Outside Director Benefit Plan (10(c)-90 to Form 10-K for the year ended December 31, 1992 in 1-10764).
+(f)	65	--	Amendment to Defined Contribution Restoration Plan of Entergy Corporation and Subsidiaries (10(a) 81 to Form 10-K for the year ended December 31, 1993 in 1-11299).
+(f)	66	--	System Executive Retirement Plan (10(a) 82 to Form 10-K for the year ended December 31, 1993 in 1-11299).
NOPSI			
(g)	1	--	Agreement, dated April 23, 1982, among NOPSI and certain other System companies, relating to System Planning and Development and Intra-System Transactions (10(a)-1 to Form 10-K for the fiscal year ended December 31, 1982, in 1-3517)
(g)	2	--	Middle South Utilities System Agency Agreement, dated December 11, 1970 (5(a)-2 in 2-41080).

(g)	3	--	Amendment dated as of February 10, 1971, to Middle South Utilities System Agency Agreement, dated December 11, 1970 (5(a)-4 in 2-41080).
(g)	4	--	Amendment, dated May 12, 1988, to Middle South Utilities System Agency Agreement, dated December 11, 1970 (5(a) 4 in 2-41080).
(g)	5	--	Middle South Utilities System Agency Coordination Agreement, dated December 11, 1970 (5(a)-3 in 2-41080).
(g)	6	--	Service Agreement with Entergy Services dated as of April 1, 1963 (5(a)-5 in 2-42523).
(g)	7	--	Amendment, dated as of January 1, 1972, to Service Agreement with Entergy Services (4(a)-6 in 2-45916).
(g)	8	--	Amendment, dated as of April 27, 1984, to Service Agreement with Entergy Services (10(a)7 to Form 10-K for the fiscal year ended December 31, 1984, in 1-3517).
(g)	9	--	Amendment, dated as of August 1, 1988, to Service Agreement with Entergy Services (10(f)-8 to Form 10-K for the fiscal year ended December 31, 1988, in 0-5807).
(g)	10	--	Amendment, dated January 1, 1991, to Service Agreement with Entergy Services (10(f)-9 to Form 10-K for the fiscal year ended December 31, 1990, in 0-5807).
*(g)	11	--	Amendment, dated January 1, 1992, to Service Agreement with Entergy Services.
(g)	12	--	Availability Agreement, dated June 21, 1974, among System Energy and certain other System companies (B to Rule 24 Certificate, dated June 24, 1974, in 70-5399).
(g)	13	--	First Amendment to Availability Agreement, dated June 30, 1977 (B to Rule 24 Certificate, dated June 30, 1977, in 70-5399).
(g)	14	--	Second Amendment to Availability Agreement, dated as of June 15, 1981 (E to Rule 24 Certificate, dated July 1, 1981, in 70-6592).
(g)	15	--	Third Amendment to Availability Agreement, dated as of June 28, 1984 (B-13(a) to Rule 24 Certificate, dated July 6, 1984, in 70-6985).
(g)	16	--	Fourth Amendment to Availability Agreement, dated as of June 1, 1989 (A to Rule 24 Certificate, dated June 8, 1989, in 70-5399).
(g)	17	--	Fourteenth Assignment of Availability Agreement, Consent and Agreement, dated as of June 15, 1985, with Deposit Guaranty National Bank, United States Trust Company of New York and Malcolm J. Hood, as Trustees (B-3(b) to Rule 24 Certificate, dated July 31, 1985, in 70-7026).
(g)	18	--	Fifteenth Assignment of Availability Agreement, Consent and Agreement, dated as of May 1, 1986, with United States Trust Company of New York, Malcolm J. Hood and Deposit Guaranty National Bank, as Trustees (B-3(b) to Rule 24 Certificate, dated June 5, 1986, in 70-7158).

(g)	19	--	Sixteenth Assignment of Availability Agreement, Consent and Agreement, dated as of May 1, 1986, with United States Trust Company of New York and Malcolm J. Hood, as Trustees (C to Rule 24 Certificate, dated June 4, 1986, in 70-7123).
(g)	20	--	Eighteenth Assignment of Availability Agreement, Consent and Agreement, dated as of September 1, 1986, with United States Trust Company of New York and Gerard F. Ganey, as Trustees (C-2 to Rule 24 Certificate, dated October 1, 1986, in 70-7272).
(g)	21	--	Nineteenth Assignment of Availability Agreement, Consent and Agreement, dated as of September 1, 1986, with United States Trust Company of New York and Gerard F. Ganey, as Trustees (C-3 to Rule 24 Certificate, dated October 1, 1986, in 70-7272).
(g)	22	--	Twenty-fourth Assignment of Availability Agreement, Consent and Agreement, dated as of July 1, 1992, with United States Trust Company of New York and Gerard F. Ganey, as Trustees (B-2(b) to Rule 24 Certificate, dated July 14, 1992, in 70-7946).
(g)	23	--	Twenty-fifth Assignment of Availability Agreement, Consent and Agreement, dated as of October 1, 1992, with United States Trust Company of New York and Gerard F. Ganey, as Trustees (B-2(b) to Rule 24 Certificate, dated November 2, 1992, in 70-7946).
(g)	24	--	Twenty-sixth Assignment of Availability Agreement, Consent and Agreement, dated as of October 1, 1992, with United States Trust Company of New York and Gerard F. Ganey, as Trustees (B-2(c) to Rule 24 Certificate, dated November 2, 1992, in 70-7946).
(g)	25	--	Twenty-seventh Assignment of Availability Agreement, Consent and Agreement, dated as of April 1, 1993, with United States Trust Company of New York and Gerard F. Ganey as Trustees (B-2(d) to Rule 24 Certificate dated May 4, 1993 in 70-7946).
(g)	26	--	Twenty-eighth Assignment of Availability Agreement, Consent and Agreement, dated as of December 17, 1993, with Chemical Bank, as Agent (B-2(a) to Rule 24 Certificate dated December 22, 1993 in 70-7561).
(g)	27	--	Twenty-ninth Assignment of Availability Agreement, Consent and Agreement, dated as of April 1, 1994, with United States Trust Company of New York and Gerard F. Ganey, as Trustees (B-2(f) to Rule 24 Certificate dated May 6, 1994, in 70-7946).
(g)	28	--	Reallocation Agreement, dated as of July 28, 1981, among System Energy and certain other System companies (B-1(a) in 70-6624).
+(g)	29	--	Post-Retirement Plan (10(e) 22 to Form 10-K for the fiscal year ended December 31, 1983, in 1-1319).
(g)	30	--	Unit Power Sales Agreement, dated as of June 10, 1982, between System Energy and AP&L, LP&L, MP&L and NOPSI (10(a) 39 to Form 10-K for the fiscal year ended December 31, 1982, in 1-3517).
(g)	31	--	First Amendment to the Unit Power Sales Agreement, dated as of June 28, 1984, between System Energy and AP&L, LP&L, MP&L and NOPSI (19 to Form 10-Q for the quarter ended September 30, 1984, in 1-3517).
(g)	32	--	Revised Unit Power Sales Agreement (10(ss) in 33-4033).

(g)	33	--	Transfer Agreement, dated as of June 28, 1983, among the City of New Orleans, NOPSI and Regional Transit Authority (2(a) to Form 8-K, dated June 24, 1983, in 1-1319).
(g)	34	--	Middle South Utilities, Inc. and Subsidiary Companies Intercompany Income Tax Allocation Agreement, dated April 28, 1988 (D-1 to Form U5S for the year ended December 31, 1987).
(g)	35	--	First Amendment, dated January 1, 1990, to the Middle South Utilities, Inc. and Subsidiary Companies Intercompany Income Tax Allocation Agreement (D-2 to Form U5S for the year ended December 31, 1989).
(g)	36	--	Second Amendment dated January 1, 1992, to the Entergy Corporation and Subsidiary Companies Intercompany Income Tax Allocation Agreement (D-3 to Form U5S for the year ended December 31, 1992).
(g)	37	--	Third Amendment dated January 1, 1994 to Entergy Corporation and Subsidiary Companies Intercompany Income Tax Allocation Agreement (D-3(a) to Form U5S for the year ended December 31, 1993).
+(g)	38	--	Executive Financial Counseling Program of Entergy Corporation and Subsidiaries (10(a)52 to Form 10-K for the year ended December 31, 1989, in 1-3517).
+(g)	39	--	Entergy Corporation Annual Incentive Plan (10(a)54 to Form 10-K for the year ended December 31, 1989, in 1-3517).
+(g)	40	--	Equity Ownership Plan of Entergy Corporation and Subsidiaries (A-4(a) to Rule 24 Certificate, dated May 24, 1991, in 70-7831).
+(g)	41	--	Supplemental Retirement Plan (10(a)69 to Form 10-K for the year ended December 31, 1992 in 1-3517).
+(g)	42	--	Defined Contribution Restoration Plan of Entergy Corporation and Subsidiaries (10(a)53 to Form 10-K for the year ended December 31, 1989 in 1-3517).
+(g)	43	--	Amendment No. 1 to the Equity Ownership Plan of Entergy Corporation and Subsidiaries (10(a)71 to Form 10-K for the year ended December 31, 1992 in 1-3517).
+(g)	44	--	Executive Disability Plan of Entergy Corporation and Subsidiaries (10(a)72 to Form 10-K for the year ended December 31, 1992 in 1-3517).
+(g)	45	--	Executive Medical Plan of Entergy Corporation and Subsidiaries (10(a)73 to Form 10-K for the year ended December 31, 1992 in 1-3517).
+(g)	46	--	Stock Plan for Outside Directors of Entergy Corporation and Subsidiaries, as amended (10(a)74 to Form 10-K for the year ended December 31, 1992 in 1-3517).
+(g)	47	--	Summary Description of Private Ownership Vehicle Plan of Entergy Corporation and Subsidiaries (10(a)75 to Form 10-K for the year ended December 31, 1992 in 1-3517).
+(g)	48	--	Agreement between Entergy Corporation and Edwin Lupberger (10(a)-42 to Form 10-K for the year ended December 31, 1985 in 1-3517).

+(g)	49	--	Agreement between Entergy Corporation and Jerry D. Jackson (10(a)-68 to Form 10-K for the year ended December 31, 1992 in 1-3517).
+(g)	50	--	Agreement between Entergy Services and Gerald D. McInvale (10(a)-69 to Form 10-K for the year ended December 31, 1992 in 1-3517).
+(g)	51	--	Agreement between System Energy and Donald C. Hintz (10(b)-47 to Form 10-K for the year ended December 31, 1991 in 1-9067).
+(g)	52	--	Summary Description of Retired Outside Director Benefit Plan (10(c)-90 to Form 10-K for the year ended December 31, 1992 in 1-10764).
+(g)	53	--	Amendment to Defined Contribution Restoration Plan of Entergy Corporation and Subsidiaries (10(a) 81 to Form 10-K for the year ended December 31, 1993 in 1-11299).
+(g)	54	--	System Executive Retirement Plan (10(a) 82 to Form 10-K for the year ended December 31, 1993 in 1-11299).

(12) Statement Re Computation of Ratios

*(a)	AP&L's	Computation of Ratios of Earnings to Fixed Charges and of Earnings to Fixed Charges and Preferred Dividends, as defined.
*(b)	GSU's	Computation of Ratios of Earnings to Fixed Charges and of Earnings to Fixed Charges and Preferred Dividends, as defined.
*(c)	LP&L's	Computation of Ratios of Earnings to Fixed Charges and of Earnings to Fixed Charges and Preferred Dividends, as defined.
*(d)	MP&L's	Computation of Ratios of Earnings to Fixed Charges and of Earnings to Fixed Charges and Preferred Dividends, as defined.
*(e)	NOPSI's	Computation of Ratios of Earnings to Fixed Charges and of Earnings to Fixed Charges and Preferred Dividends, as defined.

*(f) System Energy's Computation of Ratios of Earnings to Fixed Charges, as defined.

***(21) Subsidiaries of the Registrants**

(23) Consents of Experts and Counsel

*(a) The consent of Coopers & Lybrand L.L.P. is contained herein at page 373.

*(b) The consent of Deloitte & Touche LLP is contained herein at page 374.

*(c) The consent of Friday, Eldredge & Clark is contained herein at page 375.

*(d) The consent of Clark, Thomas & Winters is contained herein at page 376.

*(e) The consent of Sandlin Associates is contained herein at page 377.

*(f) The consent of Monroe & Lemann (A Professional Corporation) is contained herein at page 378.

*(24) Powers of Attorney

(27) Financial Data Schedule

*(a) Financial Data Schedule for Entergy Corporation and Subsidiaries as of December 31, 1994

*(b) Financial Data Schedule for AP&L as of December 31, 1994

*(c) Financial Data Schedule for GSU as of December 31, 1994

*(d) Financial Data Schedule for LP&L as of December 31, 1994

*(e) Financial Data Schedule for MP&L as of December 31, 1994

*(f) Financial Data Schedule for NOPSI as of December 31, 1994

*(g) Financial Data Schedule for System Energy as of December 31, 1994

(99) **Additional Exhibits**

GSU

(a) 1 Opinion of Clark, Thomas & Winters, a professional corporation, dated September 30, 1992 regarding the effect of the October 1, 1991 judgment in GSU v. PUCT in the District Court of Travis County, Texas (99-1 in Registration No. 33-48889).

(a) 2 Opinion of Clark Clark, Thomas & Winters, a professional corporation, dated August 8, 1994 regarding recovery of costs deferred purusant to PUCT order in Docket 6525 (99 (j) to Quarterly Report on Form 10-Q for the quarter ended June 30, 1994 in No. 1-2703).

*(a) 3 Opinion of Clark, Thomas & Winters, a professional corporation, confirming its opinions dated September 30, 1992 and August 8, 1994.

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* Filed herewith

+ Management contracts or compensatory plans or arrangements

*(23) The consent of Wise Carter Child & Caraway, Professional Association, is contained herein at page 379.

*(24) Powers of Attorney

(27) Financial Data Schedule

*(a) Financial Data Schedule for Entergy Corporation and Subsidiaries as of December 31, 1994

*(b) Financial Data Schedule for AP&L as of December 31, 1994

*(c) Financial Data Schedule for GSU as of December 31, 1994

*(d) Financial Data Schedule for LP&L as of December 31, 1994

*(e) Financial Data Schedule for MP&L as of December 31, 1994

*(f) Financial Data Schedule for NOPSI as of December 31, 1994

*(g) Financial Data Schedule for System Energy as of December 31, 1994

(99) Additional Exhibits

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(a) 1 Opinion of Clark, Thomas & Winters, a professional corporation, dated September 30, 1992 regarding the effect of the October 1, 1991 judgment in GSU v. PUCT in the District Court of Travis County, Texas (99-1 in Registration No. 33-48889)

(a) 2 Opinion of Clark Clark, Thomas & Winters, a professional corporation, dated August 8, 1994 regarding recovery of costs deferred purusant to PUCT order in Docket 6525 (99 (j) to Quarterly Report on Form 10-Q for the quarter ended June 30, 1994 in No. 1-2703)

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