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ENRON CORP

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UNITED STATES SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 8-K

CURRENT REPORT

Pursuant to Section 13 or 15(d)
of the Securities Exchange Act of 1934

Date of Report: March 1, 1994

Commission File Number 1-3423

ENRON CORP.
(Exact name of registrant as specified in its charter)

Delaware	47-0255140
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification Number)

Enron Building 1400 Smith Street Houston, Texas	77002
(Address of principal executive Offices)	(Zip Code)

(713) 853-6161
(Registrant's telephone number, including area code)

ENRON CORP. AND SUBSIDIARIES

Item 7. Financial Statements and Exhibits.

(a) Financial Statements of Enron Corp.

Financial Statements of Enron Corp. and its Consolidated Subsidiaries for the fiscal year ended December 31, 1993, including Report of Arthur Andersen & Co., Independent Public Accountants.

(b) Exhibits.

11 Calculation of Earnings Per Share

23 Consent of Arthur Andersen & Co.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned hereunto duly authorized.

ENRON CORP.

Date: March 1, 1994

By: Jack I. Tompkins
Jack I. Tompkins
Senior Vice President and Chief Information, Administrative and Accounting Officer

ENRON CORP. AND SUBSIDIARIES

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Enron Corp. and Subsidiaries

Management's Discussion and Analysis of Financial Condition and Results of Operations

The following review of the results of operations and financial condition of Enron Corp. and subsidiaries (Enron) should be read in conjunction with the Consolidated Financial Statements.

Results of Operations

Consolidated Net Income
Enron's net income for 1993 was $387 million, exclusive of a primarily non-cash charge of $54 million to adjust the deferred tax liability for the increase in the corporate Federal statutory income tax rate from 34% to 35%, compared to $306 million and $232 million for 1992 and 1991, respectively. Net income for all three years reflects improved income before interest, minority interest and income taxes as compared to the applicable preceding year. Net income for 1993 includes a $64 million pretax gain from the sale of limited partnership units in Northern Border Partners, L.P., substantially offset by the establishment of reserves for litigation and other contingencies. The net income for 1993 also includes $13 million in pretax gains from the sales of oil and gas properties and a $10 million net share of a deferred tax reduction at Enron Oil & Gas Company (EOG).

Net income for 1992 includes a $60 million nontaxable gain from the sale of stock by EOG, a $52 million pretax gain from the sale of Enron's remaining investment in Mobil Corporation common stock (Mobil stock), $6 million in pretax gains from the sales of oil and gas properties and an $11 million gain on the sale of investments. These amounts were partially offset by a $57 million pretax charge reflecting the establishment of reserves for litigation and other contingencies and a $23 million extraordinary charge relating to the early retirement of high coupon debt.

Net income for 1991 includes a $28 million pretax gain from the sale of a portion of Enron's investment in Mobil stock, a $24 million pretax gain from two favorable litigation settlements, $15 million in pretax gains from the sales of oil and gas properties and a $14 million pretax gain from the sale of certain gas processing assets.

Primary earnings per share of common stock was $1.32 in 1993, after a $0.23 per share charge applicable to the $54 million tax rate change adjustment, as compared to $1.29 and $1.03 in 1992 and 1991, respectively.

Income Before Interest, Minority Interest and Income Taxes
The following table presents income before interest, minority interest and income taxes (IBIT) for each of Enron's operating segments:

<TABLE>
<CAPTION>

(In Millions)	1993	1992	1991
<S>	<C>	<C>	<C>
Transportation and Operation	$382	$378	$343
Gas Services	169	147	71
Gas Processing	28	56	94
International Gas and Power Services	132	33	69
Exploration and Production	122	102	75
Corporate and Other	(35)	51	63
Total	$798	$767	$715

</TABLE>

Transportation and Operation

The transportation and operation segment includes Enron's regulated natural gas pipelines, construction, management and operation of pipelines, liquids plants and power facilities, Enron's crude oil marketing and transportation operations conducted by EOTT Energy Corp. (EOTT) and Enron's investment in liquids pipeline operations. The segment realized a $4 million increase in IBIT in 1993 as compared to 1992. The increase was due primarily to increases in IBIT realized by the regulated natural gas pipelines and the crude oil marketing and transportation operations, offset by declines in earnings from the liquids pipeline operations due to the sale of a significant portion of these operations in August 1992 and reduced revenues on completed construction projects. During 1992, the transportation and operations segment's IBIT increased 10% as compared to 1991 reflecting higher regulated natural gas pipeline earnings and increased revenues recognized in connection with the construction of various power projects. These increases were offset by lower earnings from EOTT and from liquids pipeline operations. The following discussion analyzes the significant changes in the various components of income before interest, minority interest and income taxes for the transportation and operation segment.

Revenues

Regulated Natural Gas Pipelines
Revenues of the regulated natural gas pipelines increased approximately $60 million (5%) during 1993 after declining $120 million (9%) in 1992 as compared to the applicable preceding year. The increase in revenues reflects increased transportation revenues recognized by Northern Natural Gas Company (Northern) primarily as a result of higher commodity

volumes and increased capacity utilization, combined with management fees earned in connection with the operation of the Argentina pipeline in which Enron owns a 17.5% interest. These increases were offset by reduced sales revenues for both Northern and Transwestern Pipeline Company (Transwestern) as those companies are now primarily transporters of natural gas.

During 1992, revenues of the regulated natural gas pipeline companies declined primarily as a result of lower sales revenues realized by Northern reflecting a 27% decline in sales volumes due to the shifting of customers from sales service to transport service and lower revenues earned by Transwestern. The decline in Transwestern's revenues reflects lower transport rates as a result of the completion by Transwestern of the recovery of certain transition costs in early 1992. These declines were partially offset by higher transportation volumes resulting from Transwestern's mainline expansion and San Juan extension which became operational at the end of the first quarter of 1992. In addition, Northern's transportation revenues increased 17% during 1992 as a result of higher volumes.

Sales and transportation volumes were as follows:

<TABLE>
<CAPTION>

Billion British Thermal Units per Day - (Bbtu/d)	Sales* 1993	1992	1991
<S>	<C>	<C>	<C>
Northern	342	495	682
Transwestern	20	33	80

<FN>
*Includes intercompany amounts.
</TABLE>

<TABLE>
<CAPTION>

Billion British Thermal Units per Day - (Bbtu/d)	Transportation* 1993	1992	1991
<S>	<C>	<C>	<C>
Northern	4,030	3,740	3,691
Transwestern	1,049	867	785

<FN>
*Includes intercompany amounts.
</TABLE>

Construction and Management Revenues
Revenues earned in connection with the construction and operation of power projects totaled $27 million in 1993 as compared to $52 million and $23 million during 1992 and 1991, respectively. The decline during 1993 reflects reduced construction revenues in connection with the Teesside power project in the United Kingdom as a result of the completion of that project in March 1993, offset by revenues earned in connection with the sales of fuel to a joint venture power project in Guatemala and fees earned in connection with the management and construction of the Milford power project in the United States.

Liquids Pipeline and EOTT
Revenues earned in connection with the liquids pipeline operations declined in 1993 and 1992 primarily as a result of the sale of those assets to Enron Liquids Pipeline, L.P., a master limited partnership formed in August 1992. Net revenues from EOTT increased approximately 39% during 1993 as a result of higher product margins.

Cost of Gas and Other Products Sold
The cost of gas and other products sold by the transportation and operation segment decreased by less than 1% during 1993 as compared to 1992 primarily as a result of higher average per unit gas purchase costs being offset by lower purchase volumes. During 1992, the cost of gas and other products sold by the transportation and operations segment declined 19% as compared to 1991 due primarily to a 27% decline in Northern's sales volumes combined with a 59% reduction in Transwestern's sales volumes. These declines were offset in part by higher average per unit gas purchase costs.

Operating Expenses
Operating expenses in the transportation and operation segment declined 10% during 1993 as compared to 1992. The decline reflects lower expenses of the regulated natural gas pipelines as a result of efficiencies gained in connection with system modernization projects, combined with a decline in operating expenses due to the previously discussed sale of the liquids pipeline operations. During 1992, operating expenses of the transportation and operation segment declined by 10% as compared to 1991 primarily as a result of lower operating expenses of the regulated pipeline group as a result of lower transmission and compression expenses reflecting lower sales volumes and the sale of the liquids pipeline operations.

Amortization of deferred contract reformation costs declined by 12% during 1993 and 19% during 1992 as compared to the applicable preceding year primarily as a result of Transwestern's completion of the recovery of certain transition costs in early 1992.

Depreciation expense for the transportation and operation segment increased $5 million (4%) during 1993 as compared to 1992 primarily as a result of a 10% increase in depreciation expense recognized by the regulated natural gas pipeline group reflecting Northern's adjustment in 1993 of accumulated depreciation in accordance with a Federal Energy Regulatory Commission (FERC) ruling. The increase in depreciation by Northern was partially offset by a decline in depreciation recorded for the liquids pipeline operations.

Other Income and Deductions
Equity in earnings of unconsolidated subsidiaries declined by $14 million (39%) during 1993 as compared to 1992 reflecting reduced earnings from Northern Border Pipeline Company (Northern Border) as a result of Enron's contribution of its investment in Northern Border to Northern Border Partners, L.P., a master limited partnership (the Partnership) and Enron's subsequent sale of a portion of its interest in the Partnership in an underwritten public offering (see Note 9 to the Consolidated Financial Statements). Additionally, during 1993 equity in earnings from Mojave Pipeline Company (Mojave) decreased as a result of the sale of Enron's investment in Mojave during 1993. Equity in earnings of unconsolidated subsidiaries of the transportation and operation segment remained virtually unchanged in 1992 as compared to 1991 as increased earnings from Northern Border were offset by lower earnings from Citrus Corp. and Mojave.

Outlook
Transportation and Operation
The transportation and operation segment should continue to provide stable earnings and cash flows during 1994. Full implementation of FERC Order 636 and the successful settlement of all significant regulatory issues by the regulated natural gas pipelines during 1993 should allow for a constant and reliable stream of cash flow. Additionally, the segment will actively promote engineering and construction services to provide incremental earnings and will seek to selectively monetize assets and reinvest proceeds in system modernization projects and reduce its overall cost structure. Expansion of the Florida Gas pipeline system should also provide growth opportunities for the transportation and operations segment.

In January 1994, Enron filed a registration statement with the Securities and Exchange Commission to sell units in a master limited partnership which will contain substantially all of the operations and assets of EOTT. EOTT will serve as general partner and own a substantial interest in the new limited partnership (see Note 3 to the Consolidated Financial Statements).

Gas Services
Enron's Gas Services segment (EGS) had a $22 million (15%) increase in income before interest, minority interest and income taxes in 1993 as compared to 1992. The increase was due primarily to increased production payments arranged, successful long-term contracting efforts and the continued growth of the physical and financial risk management services provided to the natural gas business. Offsetting these increases were declines in earnings associated with EGS's North American power ventures and natural gas liquids (NGL) marketing activities. Each year's results also include earnings from the Sithe Energies contract (Sithe). The Sithe contract, which was signed in 1992, provides for Enron Power Services Inc. to deliver approximately 1.5 trillion cubic feet of gas over the next 20 years (five years on a fixed-price basis) to fuel Sithe's independent power project in upstate New York. Income before interest, minority interest and income taxes increased $76 million (107%) in 1992 as compared to 1991 due primarily to long-term contracting and production payment activities.

Statistics for the gas services segment are as follows:

<TABLE>
<CAPTION>

	1993	1992	1991
Physical and Notional Sales (Bbtu/d)*			
<S>	<C>	<C>	<C>
Firm	4,310	2,632	1,593
Interruptible	828	893	1,597
Financial Settlements (notional)	5,027	1,536	424
Total	10,165	5,061	3,614
Transportation Volumes (Bbtu/d)*	571	536	498
Liquids Marketing Volumes			
NGL Marketed (MMgal)	2,506	3,388	2,512
Gross Margin ($/Gal)	$0.008	$0.009	$0.010
MTBE			
Marketing Volumes (MMgal)	254	28	-
Owned Production (MMgal)	128	15	-
Gross Margin ($/Gal)	$0.197	$0.175	$ -
Production Payments and Financings Arranged (in millions)	$ 413	$ 516**	$ 121
Fixed Price Contract Originations (TBtue)	3,781	2,165	964

<FN>
*Includes intercompany amounts.
**Includes $327 million of production payments promoted for EOG.
</TABLE>

EGS's strategy is to provide predictable pricing, reliable delivery and low cost capital to its customers. EGS provides these services through a variety of financial instruments including forward contracts, swap agreements, options, futures and other contractual commitments.

These services can be categorized into four business lines: Gas, Power, Finance and Liquids. The following discussion analyzes the contributions to income before interest, minority interest and income taxes and the future outlook for each of the businesses.

Gas. The Gas operations include price risk management and origination activities as well as the physical natural gas trading and transportation activities of Enron Gas Marketing, Houston Pipe Line Company, Enron Access, the Louisiana Resources companies and the Canadian gas supply and marketing operations. The earnings from these activities increased 30% in 1993 primarily as a result of increases in sales volumes. The volume increase is primarily attributable to continued growth in the derivatives business, the September 1992 acquisition of Enron Access, the April 1993 acquisition of Louisiana Resources and expansion into the Canadian market. The 1993 results also include earnings from significant fixed and index-priced contract originations and management of the existing contract portfolio. Earnings during 1992 included fixed price originations and earnings from the marketing and trading activities and was virtually unchanged as compared to 1991.

During 1994, EGS anticipates continued strong performance from its gas business. Growth in the physical and financial trading activities is expected despite continued competition from financial and industry companies, particularly in the derivatives area. Additionally, contract originations should increase as the impact of FERC Order 636 becomes more evident.

Power. EGS's Power business includes activities in North America such as providing natural gas contract services to the power industry; managing, acquiring and developing power-related assets and joint ventures; and marketing and supplying electricity. Power's earnings declined 15% during 1993 due primarily to the inclusion in 1992 of earnings associated with the Richmond and Milford power projects. The 1993 and 1992 results also included earnings related to the gas forward sales contract with Sithe. Earnings in 1993 and 1992 also included significant contract originations involving sales of gas to other power generation facilities. The 1992 results were significantly higher than 1991 reflecting the initiation of contract origination activities.

The Power operations will benefit in 1994 from the opportunities being created in the power marketing area as a result of the continuing regulatory and economic changes in the electric industry. During 1994, EGS expects to compete as an independent marketer of electricity. Additionally, EGS will aggressively continue marketing of natural gas to independent power projects as well as electric utilities converting to natural gas in response to the Clean Air Act of 1990.

Finance. Enron Finance Corp. (EFC) secures natural gas supplies from independent producers through a variety of financial transactions, primarily volumetric production payments. EFC arranges these transactions through financial entities and provides related price risk management services. Additionally, EGS purchases the natural gas and crude oil associated with these transactions. EFC's earnings increased 50% in 1993 due primarily to increased non-affiliated production payments and financings arranged. EFC's earnings increased during 1992 as compared to 1991 due to increased production payment activities. From inception through December 31, 1993, production payments and financings arranged total over $1 billion.

In 1994, EFC expects continued growth in its business resulting primarily from offerings of innovative alternative financing to producers. This activity will include production payments, debt and equity financings, as well as other products. During 1993, Joint Energy Development Investments, a limited partnership, was formed comprised of an EGS subsidiary as general partner and the California Public Employees Retirement System (CalPERS) as limited partner. The partnership will provide significant capital for energy investments.

Liquids. The Liquids business of EGS includes the North American natural gas liquids (NGL) marketing activities and the Clean Fuels business which consists of the methanol and methyl tertiary butyl ether (MTBE) businesses. Liquids earnings were virtually unchanged from 1992 to 1993. Earnings from the Clean Fuels business increased as a result of higher MTBE volumes and the impact of reflecting contractual commitments at market value. The Clean Fuels increase was partially offset by a decrease in the NGL marketing results due to lower volumes and margins. Liquids earnings declined 40% from 1991 to 1992 due primarily to expenses associated with the start-up of the Clean Fuels business and the impact of lower NGL prices.

During 1994, EGS's Liquids business expects to improve its NGL marketing results by expanding to provide derivative products in that area. Additionally, in the MTBE business, EGS plans to continue development of its merchant business by actively marketing MTBE, including long-term and fixed margin-based pricing terms. Although current MTBE prices continue to be weak, market conditions are expected to improve as the Clean Air Act of 1990 mandates the increased use of reformulated gasoline (a primary market for MTBE).

Other. EGS's net unallocated expenses such as rent, systems expenses and other support group costs increased 27% in 1993 as compared to 1992 due primarily to continued expansion into new markets, system upgrades and the generally increased level of activity. Expenses increased 45% from 1991 to 1992 due also to increased activity and establishment of certain contingency reserves.

Gas Processing

The income before interest and taxes of the gas processing segment totaled $28 million in 1993 as compared to $56 million in 1992 and $94 million in 1991. The declines in both 1992 and 1993 as compared to the applicable preceding years were attributable primarily to lower processing margins reflecting higher natural gas feedstock prices and lower product prices. Volume and price statistics for the gas processing segment (including intercompany amounts) are detailed below:

<TABLE>
<CAPTION>

	1993	1992	1991
<S>	<C>	<C>	<C>
Total Production Volumes (MMgal)	1,334	1,296	1,153
Gross Margin (per gal.)	$0.089	$0.112	$0.163
Product Prices			
Average at Mt. Belvieu (cents/gallon)			
Ethane	21.09	23.64	22.32
Propane	31.24	32.06	33.95
Normal Butane	36.52	39.17	42.44
Isobutane	40.09	46.39	47.21
Natural Gasoline	40.97	45.51	49.60

</TABLE>

Revenues
Revenues of the gas processing segment increased 4% during 1993 after an increase of 8% during 1992 as compared to the applicable preceding year. In both 1993 and 1992, the increase in revenues was primarily caused by increased production volumes partially offset by reduced product prices.

Costs and Expenses
The cost of products sold by the gas processing segment increased 22% in 1993 as compared to 1992 and 20% in 1992 as compared to 1991. The increases in both years were attributable to higher natural gas feedstock prices combined with higher production volumes. The increases in cost of products sold coupled with reduced product prices resulted in declines in gross margin of the domestic gas processing segment of 48% in 1993 and 18% in 1992.

Other Income and Deductions
Other income increased $23 million during 1993 as compared to 1992 primarily as a result of gains realized on the sales of certain coal handling and NGL assets.

Outlook
In 1994, Enron plans to mitigate the market risk inherent in the gas processing business through hedging techniques. Additionally, cost cutting and streamlining actions have recently been completed, positioning the business to maximize earnings opportunities.

International Gas and Power Services
Enron's international gas and power services segment includes its international power, pipeline and natural gas liquids marketing operations. International power operations include the development and promotion of power and natural gas projects worldwide. Income before interest and taxes for the international gas and power services group totaled $132 million during 1993, $33 million in 1992 and $69 million in 1991. The increase in IBIT between 1992 and 1993 and the decline between 1991 and 1992 primarily reflects the promotion and development activities of its power operations. The 1993 increase also reflects earnings from the Argentina pipeline operations acquired in the fourth quarter of 1992.

Revenues
Revenues of the international gas and power services segment declined 12% during 1993 as compared to 1992 primarily as a result of decreased revenues earned by the international gas liquids marketing operations. These declines were caused by a 45% decline in marketing volumes as compared to the prior year, reflecting reduced spot market activity. The decline in liquids marketing revenues was partially offset by a $102 million increase in revenues in the power operations. The increase reflects revenues earned in connection with the promotion and development of liquids and power projects of which approximately $55 million is related to revenues earned in connection with the promotion and sale of liquids processing facilities at Teesside.

During 1992, revenues of the international gas and power services segment declined 15% as compared to 1991 primarily as a result of lower liquids marketing and power revenues. Liquids marketing revenues declined by 13% reflecting a 14% decline in marketing volumes. Power revenues declined $46 million (87%) primarily as a result of promotion and development revenues earned in connection with the Teesside power project in 1991.

Costs and Expenses
The cost of gas and other products sold by the international gas and power services segment declined by 24% in 1993 as compared to 1992 and reflected the previously mentioned decline in international liquids marketing volumes. Operating expenses increased $20 million (40%) during 1993 as compared to 1992 primarily as a result of higher operating expenses incurred in connection with increased activities in the power operations area. Operating income for the segment increased $69 million during 1993 as compared to 1992 as a result of the previously mentioned successful power development and promotion activities and improved margins earned by the international liquids marketing operations reflecting a reduction in spot market transactions which negatively impact margin. Operating income declined by $45 million during 1992 as compared to 1991 primarily as a result of the recognition in 1991 of promotion and development revenues earned in connection with the Teesside power project.

Other Income and Deductions
Equity in earnings of unconsolidated subsidiaries of the international gas and power services segment increased $36 million during 1993 as compared to 1992 primarily as a result of $23 million in earnings from the Argentina pipeline project and $12 million in earnings from the Teesside power project which was placed in commercial operation during the first quarter of 1993. Other income, net, declined $7 million during 1993 primarily as a result of lower interest income earned by the power operations in 1993 as compared with 1992 combined with gains on asset sales realized by Enron's operations in South America (Enron Americas) during 1992. Other income increased $8 million during 1992 as compared to 1991 primarily as a result of the gain on asset sales realized by Enron Americas.

Outlook
The objective of the international gas and power services segment is to deliver Enron's extensive product line to the international marketplace including Enron's product concepts in the areas of marketing and risk management of natural gas based products. Growth opportunities in that market should result from the current and projected high demand for electrical power generation, the under utilization of natural gas reserves throughout the world and increased environmental awareness.

Exploration and Production
Income before interest, minority interest and income taxes for EOG increased $20 million (20%) during 1993 and $27 million (36%) during 1992 as compared to the applicable preceding year due primarily to higher natural gas prices and volumes, and lower per unit operating costs.

Volume and price statistics are as follows (including intercompany amounts):

<TABLE>
<CAPTION>

<S>	1993 <C>	1992 <C>	1991 <C>
Wellhead Delivered Volumes			
Natural Gas (MMcf/d)	709(a)	564(a)	491
Crude Oil and Condensate (MBbl/d)	8.9	8.5	8.2
Natural Gas Liquids (MBbl/d)	0.6	0.7	0.6
Wellhead Average Prices			
Natural Gas ($/Mcf)	$ 1.92(b)	$ 1.58(b)	$ 1.37
Crude Oil and Condensate ($/Bbl)	$16.37	$17.90	$18.78
Natural Gas Liquids ($/Bbl)	$11.12	$10.69	$11.64
Other Natural Gas Marketing Volumes (MMcf/d)	293(a)	255(a)	237
Average Gross Revenue ($/Mcf)	$ 2.57	$ 2.62	$ 2.63
Associated Costs ($/Mcf) (including transportation and exchange differentials)	$ 2.32	$ 1.99	$1.75

<FN>
(a) Includes an annual average of 81.0 MMcf per day in 1993 and 27.6 MMcf per day in 1992 delivered under the terms of a volumetric production payment agreement effective October 1, 1992, as amended.
(b) Includes an average equivalent wellhead value of $1.57 per Mcf in 1993 and $1.70 per Mcf in 1992 for the volumes detailed in Note (a) above, net of transportation costs.
</TABLE>

The following discussion further analyzes the significant changes in EOG's results.

Revenues
EOG's gross revenues increased $133 million (24%) during 1993 and $84 million (18%) in 1992 as compared to the applicable preceding year. The increased revenues in 1993 are attributable to a 22% increase in average wellhead natural gas prices combined with a 26% increase in average wellhead natural gas volumes. The increased natural gas volumes primarily reflect the effects of exploration and development activities relating to tight gas sand formations. The increased revenues in 1992 are attributable to a 15% increase in average wellhead natural gas delivered volumes combined with a 15% increase in average wellhead natural gas prices. Although exploration and development efforts resulted in deliverability increases in certain core areas, the earnings in 1992 and 1991 were mitigated by voluntary curtailments initiated due to lower than acceptable prices during certain periods.

Costs and Expenses
The cost of gas sold by the exploration and production segment in connection with other natural gas marketing activities increased 18% in 1993 as compared to 1992 and 23% in 1992 as compared to 1991. The increase in 1993 as compared to 1992 was due to 17% higher average associated costs per Mcf combined with a 15% increase in natural gas marketing volumes. The increase in 1992 was due to 14% higher average associated costs per Mcf combined with 8% higher other natural gas marketing volumes.

Operating expenses for the exploration and production segment increased $35 million (24%) in 1993 compared to 1992 and remained stable in 1992 as compared to 1991. The increase in 1993 relates to higher lease and well expenses and exploration expenses primarily due to expanded domestic and international operations. Depreciation, depletion and amortization expense increased 39% in 1993 and 12% in 1992 as compared to prior years. The increases in both years primarily reflect increased production volumes. On a per unit natural gas equivalent volumes delivered basis, depreciation, depletion and amortization expense increased to $0.89 per thousand cubic feet equivalent ("Mcfe" - natural gas equivalents are determined using the ratio of 6.0 Mcf of natural gas to 1.0 barrel of crude oil, condensate or natural gas liquids) in 1993 from $0.79 per Mcfe in 1992 and $0.81 per Mcfe in 1991 primarily due to higher costs associated with tight gas sand drilling activities.

Taxes, other than income taxes, increased $7 million (25%) from 1992 to 1993 due to increased production volumes and revenues, partially offset by continuing benefits associated with certain state severance tax exemptions allowed on high cost natural gas sales and a refund received in 1993 of franchise taxes paid in prior years. Taxes, other than income taxes, increased $10 million (56%) from 1991 to 1992 due to increased production volumes and revenues, increases in certain ad valorem and state franchise taxes in 1992, and earnings benefits realized in 1991 associated with the refund of certain state natural gas severance taxes resulting from overpayments in prior years. These increases were mitigated by Texas severance tax exemptions for high cost gas production that were in effect for the full year.

Total per unit operating costs for lease and well expense, DD&A, general and administrative expense, interest expense, and taxes other than income increased $0.03 Mcfe, averaging $1.43 per Mcfe during 1993 compared to $1.40 per Mcfe for 1992.

Other Income and Deductions
The exploration and production segment's other income was $20 million in 1993 as compared to $3 million in 1992 and $12 million in 1991. Gains on property sales were the primary components of other income during each of the three years and totaled $13 million in 1993, $6 million in 1992 and $15 million in 1991.

Outlook
While there still exists a good deal of uncertainty as to the direction of future natural gas price trends, some recent experiences may suggest a converging of the overall supply/demand relationship reflecting, at least partially, the significantly reduced level of drilling activity during recent years. EOG's management remains confident that continually increasing recognition of natural gas as a more environmentally friendly source of energy along with the availability of significant domestically sourced supplies will result in further increases in demand and a strengthening of the overall natural gas market over time. Being primarily a natural gas producer, EOG is more significantly impacted by changes in natural gas prices than by changes in crude oil and condensate prices. However, the use by the exploration and production segment from time to time of various commodity price hedging mechanisms will tend to mitigate this level of sensitivity. Enron has hedged the vast majority of its anticipated 1994 natural gas production by selling forward at recent prices.

EOG will continue to focus development and certain exploration expenditures in its core and other major producing areas, and include limited exploratory exposure in areas outside of North America. Expenditure plans for 1994 will continue to be focused toward certain areas that were not addressed as actively in the recent past due to the increased emphasis on tight gas sand drilling opportunities during 1991 and 1992. EOG will continue expenditures in new areas outside of North America, primarily for additional development operations in Trinidad, new development operations in other countries and the continued evaluation of coalbed methane recovery potential in France, Australia, China and certain other countries.

Corporate and Other
The corporate and other segment's income before interest, minority interest and income taxes was an expense of $35 million in 1993 as compared to income of $51 million in 1992 and $63 million in 1991. During 1993, the segment recognized higher administrative and general expenses. Included in 1992 are the previously discussed gains from the sale of stock by EOG and sales of Mobil stock partially offset by charges related to the establishment of reserves for litigation and other contingencies. Included in 1991 are the previously discussed gains related to sales of Mobil stock, two favorable litigation settlements and the sale of certain gas processing assets.

Interest Expense and Income Taxes
Interest and related charges, net, is shown on the Consolidated Income Statement net of interest capitalized. The net expense for 1993 decreased $30 million (9%) from 1992. The decrease is primarily due to lower interest rates. The net expense for 1992 decreased $43 million (12%) from 1991. The decrease is primarily due to a decrease in short-term interest rates and lower total obligations. Short-term borrowings averaged $591 million during 1993 as compared to $588 million during 1992 and $500 million during 1991 while the average interest rate on short-term debt fell to 3.3% in 1993 from 3.9% in 1992 and 6.3% in 1991.

Exclusive of the adjustment for the increase in the U.S. corporate Federal statutory income tax rate from 34% to 35%, income tax expense declined slightly during 1993 as compared to 1992 as increased pretax income was offset by utilization of increased tight gas sand tax credits. Although income before income taxes increased, income taxes decreased in 1992 as compared to 1991 primarily due to the inclusion of a nontaxable gain from the sale of stock by EOG and utilization of increased tight gas sand tax credits.

Extraordinary Items
The extraordinary loss results primarily from the early retirement of $599 million principal amount of 10.625% senior subordinated debentures in September 1992.

Financial Condition
Cash From Operating Activities
Net cash provided by operating activities totaled $468 million during 1993 as compared to $330 million in 1992. The increase primarily reflects higher income levels in 1993 and the prepayment of $150 million made in 1992 for information technology services.

Cash From Investing Activities
Cash used in investing activities totaled $639 million during 1993 as compared to $43 million during 1992. The change primarily reflects increased expenditures in connection with Enron's investment in Argentina pipeline operations, Teesside and other power projects. Additionally, during 1992, EOG recorded proceeds of $327 million under the terms of a volumetric production payment transaction (see Note 8 to the Consolidated Financial Statements). Proceeds from the sales of assets totaled $454 million during 1993 as compared to $388 million during 1992. The 1993 amounts include approximately $217 million in connection with the sale of Enron's interest in Northern Border Partners, L.P., $100 million from the sale of information technology assets and $42 million realized from the sale of exploration and production properties. Proceeds from the sale of assets during 1992 included $62 million from the sale of Mobil stock, $138 million, net, realized on the sale of certain liquids pipeline assets to Enron Liquids Pipeline, L.P., $121 million from the sale of certain pipeline assets by Enron Gas Services and $33 million realized from the sale of exploration and production properties.

Cash From Financing Activities
Net cash provided by financing activities totaled $170 million during 1993 as compared to the use of $339 million in 1992. The difference in cash flow from financing activities between 1993 and 1992 was the retirement in 1992 of $1.1 billion of long-term debt primarily through the utilization of call provisions available on higher coupon debt issues. The repayments of long-term debt were partially funded by proceeds from the sales of common stock by Enron and EOG. During 1993, Enron issued $614 million of long-term debt while retiring $450 million principal amount of long-term borrowings. Other cash outflows during 1993 included $190 million of cash dividend payments on common and preferred stock and $23 million in repayments of other long-term obligations. In addition to the debt issuances discussed above, financing cash inflows during 1993 included $214 million from the issuance of preferred stock by a wholly-owned subsidiary of Enron (see Note 10 to the Consolidated Financial Statements).

Working Capital
At December 31, 1993, Enron had a working capital deficit of $657 million. Enron is able to fund its deficit in working capital through the utilization of credit facilities which, at December 31, 1993, provided for up to $2.2 billion of committed and uncommitted credit. Certain of the credit agreements contain prefunding covenants. However, such covenants are not expected to materially restrict Enron's access to funds under these agreements. At December 31, 1993, Enron had $144 million outstanding under the uncommitted agreements. In addition, Enron sells commercial paper and has agreements to sell up to $800 million of accounts receivable, thus providing short-term financing to meet seasonal working capital needs. Management believes that the sources of funding described above are sufficient to meet short- and long-term liquidity needs not met by cash flows from operations.

Capital Expenditures

Capital expenditures by operating segment are detailed as follows:

<TABLE>
<CAPTION>

(In Millions)	1994 Estimate	1993	1992	1991
<S>	<C>	<C>	<C>	<C>
Transportation and Operation	$123	$152	$140	$396
Gas Services	45	78	45	47
Gas Processing	8	24	34	110
International Gas and Power Services	16	53	41	28
Exploration and Production*	394	383	362	212
Corporate and Other	8	5	12	35
Total	$594	$695	$634	$828

<FN>
*Excludes exploration expenses of $56 million (estimate), $55 million, $44 million, and $46 million for 1994, 1993, 1992 and 1991, respectively.
</TABLE>

Capital expenditures by the transportation and operation segment increased $12 million during 1993 as compared to 1992. The decline during 1992 as compared to 1991 reflects the completion in early 1992 of Transwestern's pipeline expansion project and its San Juan lateral project which began during 1991.

Capital expenditures of the gas services segment increased $33 million during 1993 as compared to 1992 primarily as a result of the acquisition of gas storage assets and systems improvement costs.

The exploration and production segment's capital expenditures increased from $362 million in 1992 to $383 million in 1993. The increase was primarily attributable to increased domestic drilling activity with reduced emphasis on development drilling expenditures associated with tight gas sand formations. Enron also implemented its first development program outside of North America. The increase in capital spending by the exploration and production segment in 1992 compared to 1991 reflects development drilling expenditures associated with tight gas sand drilling activities and the acquisition in December 1992 of $40 million of producing properties in Canada.

Capital expenditures during 1994 are expected to total approximately $594 million. However, the overall level of capital spending as well as spending by individual business segments will vary depending upon conditions in the energy market and other related economic conditions. In addition, equity investments are expected to be approximately $387 million of which approximately $150 million for the Florida Gas Transmission Company expansion and approximately $160 million for various international power projects. Management believes that the capital expenditure program will be funded by a combination of internally generated funds and proceeds from dispositions of selected assets.

Capitalization
Total capitalization at December 31, 1993 of $5.7 billion was comprised of total long-term debt of $2.7 billion, shareholders' equity of $2.6 billion, preferred stock of subsidiary company of $.2 billion and minority interests of $.2 billion. Debt as a percentage of total capitalization decreased to 46.7% at December 31, 1993 as compared to 47.7% at December 31, 1992. The improvement primarily reflects higher net income and the issuance of preferred stock by Enron Capital L.L.C., the proceeds of which were used to reduce debt and other corporate purposes. Additionally, the average cost of long-term debt declined to 8.2% at December 31, 1993 from 8.9% at December 31, 1992. The decline was accomplished primarily through the retirement of additional higher coupon long-term debt which was subject to call provisions during 1993.

Report of Independent Public Accountants

To the Shareholders and Board of Directors of Enron Corp.:

We have audited the accompanying consolidated balance sheet of Enron Corp. (a Delaware corporation) and subsidiaries as of December 31, 1993 and 1992, and the related consolidated statements of income, cash flows and changes in shareholders' equity accounts for each of the three years in the period ended December 31, 1993. These financial statements are the responsibility of Enron Corp.'s management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of Enron Corp. and subsidiaries as of December 31, 1993 and 1992, and the results of their operations, cash flows and changes in shareholders' equity accounts for each of the three years in the period ended December 31, 1993, in conformity with generally accepted accounting principles.

Arthur Andersen & Co.
Houston, Texas
February 18, 1994

<TABLE>
Enron Corp. and Subsidiaries
Consolidated Income Statement
(In Thousands, Except Per Share Amounts)
<CAPTION>

	Year Ended December 31, 1993	1992 (Restated)	1991 (Restated)
<S>	<C>	<C>	<C>
Revenues			
Natural gas and gas liquids	$6,125,638	$4,712,422	$4,270,720
Transportation	767,911	688,297	637,082
Other	1,078,933	1,008,554	775,139
	7,972,482	6,409,273	5,682,941
Costs and Expenses			
Cost of gas sold	3,856,499	2,502,253	2,029,232
Cost of other products sold	1,709,527	1,720,142	1,616,611
Operating expenses	1,057,415	936,040	914,538
Amortization of deferred contract reformation costs	89,240	101,253	124,947
Oil and gas exploration expenses	75,743	59,178	58,959
Depreciation, depletion and amortization	458,188	376,019	365,957
Taxes, other than income taxes	108,386	100,616	74,760
	7,354,998	5,795,501	5,185,004
Operating Income	617,484	613,772	497,937
Other Income and Deductions			
Equity in earnings of unconsolidated subsidiaries	73,293	56,545	55,228
Interest income	31,457	53,623	56,051
Gain on sale of stock by subsidiary company	-	59,615	-
Other, net	75,433	(16,373)	106,086
Income Before Interest, Minority Interest and Income Taxes	797,667	767,182	715,302
Interest and Related Charges, net	300,149	330,282	373,492
Dividends on Preferred Stock of Subsidiary	2,137	-	-
Minority Interest	27,605	17,632	7,210
Income Taxes	89,077	90,468	102,454
Income Tax Rate Adjustment	46,177	-	-
Income Before Extraordinary Items	332,522	328,800	232,146
Extraordinary Items	-	(22,615)	-
Net Income	332,522	306,185	232,146
Preferred Stock Dividends	16,919	22,109	24,740
Earnings on Common Stock	$ 315,603	$ 284,076	$ 207,406
Earnings Per Share of Common Stock			
Primary			
Income before extraordinary items	$ 1.32	$ 1.39	$ 1.03
Extraordinary items	-	(.10)	-
	$ 1.32	$ 1.29	$ 1.03
Fully Diluted			
Income before extraordinary items	$ 1.25	$ 1.30	$ .98
Extraordinary items	-	(.09)	-
	$ 1.25	$ 1.21	$ .98
Average Number of Common Shares Used in Primary Computation	239,019	219,965	202,080

<FN>
The accompanying notes are an integral part of these consolidated financial statements.
</TABLE>

<TABLE>
Enron Corp. and Subsidiaries
Consolidated Balance Sheet

<CAPTION>

December 31,

(In Thousands)	1993	1992 (Restated)
<S>	<C>	<C>
Assets		
Current Assets		
Cash and cash equivalents	$ 140,240	$ 141,689
Trade receivables (net of allowance for doubtful accounts of $21,873 and $14,555, respectively)	783,603	514,505
Other receivables	205,956	96,227
Transportation and exchange gas receivable	102,887	123,572
Inventories	197,737	293,809
Deferred contract reformation costs	103,520	103,520
Assets from price risk management activities	279,715	170,279
Other	204,952	208,255
Total Current Assets	2,018,610	1,651,856
Investments and Other Assets		
Investments in and advances to unconsolidated subsidiaries	697,084	636,062
Deferred contract reformation costs	168,479	266,466
Assets from price risk management activities	887,342	360,861
Other	1,010,028	850,595
Total Investments and Other Assets	2,762,933	2,113,984
Property, Plant and Equipment, at cost		
Transportation and operations	4,070,325	3,862,076

Gas services	3,543,991	3,483,504
Exploration and production, successful efforts accounting	2,772,220	2,475,371
International gas and power services	135,918	54,672
Gas processing	265,782	326,505
Corporate and other	98,622	213,148
	10,886,858	10,415,276
Less accumulated depreciation, depletion and amortization	4,164,086	3,869,513
Net Property, Plant and Equipment	6,722,772	6,545,763
Total Assets	$11,504,315	$10,311,603

<FN>
The accompanying notes are an integral part of these consolidated financial statements.
</TABLE>

<TABLE>
Enron Corp. and Subsidiaries
Consolidated Balance Sheet

<CAPTION>

(In Thousands)	December 31, 1993	1992 (Restated)
<S>	<C>	<C>
Liabilities and Shareholders' Equity		
Current Liabilities		
Accounts payable	$ 1,477,290	$ 1,323,782
Transportation and exchange gas payable	98,569	107,559
Accrued taxes	88,837	105,692
Accrued interest	53,292	52,712
Billings in excess of costs on uncompleted contracts	45,380	55,487
Liabilities from price risk management activities	609,403	283,877
Deferred revenue	48,804	87,599
Other	254,014	201,220
Total Current Liabilities	2,675,589	2,217,928
Long-Term Debt	2,661,240	2,458,924
Deferred Credits and Other Liabilities		
Deferred income taxes	1,860,237	1,879,027
Deferred revenue	327,802	439,847
Liabilities from price risk management activities	330,209	135,233
Other (including Flexible Equity Trust, Note 11)	615,839	482,930
Total Deferred Credits and Other Liabilities	3,134,087	2,937,037
Commitments and Contingencies (Notes 9, 14, 15, 16 and 18)		
Minority Interests	196,275	179,397
Preferred Stock of Subsidiary Company	213,750	-
Shareholders' Equity		
Preferred stock, cumulative, $100 par value, 1,500,000 shares authorized, no shares issued	-	-
Preference stock, cumulative, $1 par value, 10,000,000 shares authorized, no shares issued	-	-
Second preferred stock, cumulative, $1 par value, 5,000,000 shares authorized, 1,496,677 shares and 1,829,641 shares of $10.50 Cumulative Second Preferred Convertible Stock issued, respectively	149,668	182,964
Common stock, 600,000,000 shares authorized, 249,095,312 shares $0.10 par value, and 118,766,088 shares $10.00 par value, issued, respectively	24,910	1,187,661
Additional paid-in capital	1,707,938	324,944
Retained earnings	1,104,986	959,522
Cumulative foreign currency translation adjustment	(138,704)	(118,160)
Common stock held in treasury (174,700 shares at December 31, 1992)	-	(8,100)
Other	(225,424)	(10,514)
Total Shareholders' Equity	2,623,374	2,518,317
Total Liabilities and Shareholders' Equity	$11,504,315	$10,311,603

<FN>
The accompanying notes are an integral part of these consolidated financial statements.
</TABLE>

<TABLE>
Enron Corp. and Subsidiaries
Consolidated Statement of Cash Flows

<CAPTION>

(In Thousands)	Year Ended December 31, 1993	1992 (Restated)	1991 (Restated)
<S>	<C>	<C>	<C>
Cash Flows From Operating Activities			
Reconciliation of net income to net cash provided by operating activities			
Income before extraordinary items	$ 332,522	$ 328,800	$ 232,146
Depreciation, depletion and amortization	458,188	376,019	365,957
Oil and gas exploration expenses	75,743	59,178	58,959
Amortization of deferred contract reformation costs	89,240	101,253	124,947
Deferred income taxes	51,200	(14,647)	(42,942)
Gains on sales of stock by subsidiary company and other assets	(115,586)	(136,249)	(58,353)
Regulatory, litigation and other contingency adjustments	58,944	42,549	(11,036)
Changes in components of working capital	(76,513)	(157,234)	349,264
Deferred contract reformation costs	(136,383)	(129,694)	(84,512)
Deferred revenues	12,669	32,679	20,851
Prepaid information technology services	-	(150,000)	-
Net assets from price risk management activities	(115,415)	(15,892)	(96,138)
Other, net	(166,320)	(6,898)	(45,463)
Net Cash Provided by Operating Activities	468,289	329,864	813,680
Cash Flows From Investing Activities			
Proceeds from sales of investments and other assets	453,977	387,788	277,086
Production payment transactions, net	(73,867)	301,395	-
Additions to property, plant and equipment	(688,032)	(596,885)	(707,083)
Other capital expenditures	(7,405)	(37,656)	(120,837)
Other, net	(323,916)	(97,961)	(71,231)
Net Cash Used in Investing Activities	(639,243)	(43,319)	(622,065)
Cash Flows From Financing Activities			
Net increase (decrease) in short-term borrowings	42,767	(142,651)	(261,179)
Issuance of long-term debt	613,938	700,000	412,783
Decrease in long-term debt	(450,161)	(1,116,911)	(59,120)
Decrease in other long-term obligations	(22,757)	(72,140)	(73,972)
Issuance of preferred stock of subsidiary	213,750	-	-
Issuance of common stock	22,882	399,355	-
Issuance of common stock by subsidiary	-	111,861	-
Dividends paid	(189,769)	(174,880)	(154,274)
Net acquisition of treasury stock	(71,145)	(37,524)	(65,755)
Other, net	10,000	(5,818)	18,000
Net Cash Provided by (Used in) Financing Activities	169,505	(338,708)	(183,517)
Increase (Decrease) in Cash and Cash Equivalents	(1,449)	(52,163)	8,098
Cash and Cash Equivalents, Beginning of Year	141,689	193,852	185,754
Cash and Cash Equivalents, End of Year	$ 140,240	$ 141,689	$ 193,852

<FN>
The accompanying notes are an integral part of these consolidated financial statements.
</TABLE>

<TABLE>
Enron Corp. and Subsidiaries
Consolidated Statement of Changes in Shareholders' Equity Accounts
<CAPTION>

(In Thousands)	Convertible Preferred Stock	Common Stock	Additional Paid-in Capital	Retained Earnings (Restated)	Cumulative Foreign Currency Translation Adjustment	Treasury Stock	Other (Including Flexible Equity Trust)
<S>	<C>	<C>	<C>	<C>	<C>	<C>	<C>
Balance at December 31, 1990	$237,585	$ 506,244	$ 260,792	$ 966,096	$ (76,982)	$ (6,555)	$ (49,633)
Net income				232,146			
Cash dividends							
Common stock				(126,957)			
Preferred stock				(24,740)			
Treasury stock reissued			(620)			16,837	(3,483)
Purchase of treasury stock						(76,696)	
Exchange of common stock for convertible preferred stock	(14,850)	5,068	9,782				
Exchange of common stock for convertible debentures		2,000	8,524				
Common stock issued		3,032	13,909				
Translation adjustments					(128)		
Common stock split		516,344	(293,482)	(222,862)			
Other			1,095			(984)	19,449
Balance at December 31, 1991	222,735	1,032,688	-	823,683	(77,110)	(67,398)	(33,667)
Net income				306,185			
Cash dividends							
Common stock				(148,237)			
Preferred stock				(22,109)			
Treasury stock reissued			(12,083)			49,737	(351)
Purchase of treasury stock						(62,933)	
Exchange of common stock for convertible preferred stock	(39,771)	27,147	12,624				
Exchange of common stock for convertible debentures		12,346	5,117			73,043	
Common stock issued		115,480	319,794				
Translation adjustments					(41,050)		
Other			(508)			(549)	23,504
Balance at December 31, 1992	182,964	1,187,661	324,944	959,522	(118,160)	(8,100)	(10,514)
Net income				332,522			
Cash dividends							
Common stock				(170,457)			
Preferred stock				(16,919)			
Treasury stock reissued			(7,607)			42,665	(5,601)
Purchase of treasury stock						(89,105)	
Exchange of common stock for convertible preferred stock	(33,296)	3,573	(25,289)			55,012	
Common stock issued		4,645	245,227				(219,563)
Common stock split and reduction of par value to $0.10		(1,170,969)	1,170,969				
Translation adjustments					(20,544)		
Other			(306)	318		(472)	10,254
Balance at December 31, 1993	$149,668	$ 24,910	$1,707,938	$1,104,986	$(138,704)	$ -	$(225,424)

<FN>
The accompanying notes are an integral part of these consolidated financial statements.
</TABLE>

Enron Corp. and Subsidiaries
Notes to the Consolidated Financial Statements

1. Summary of Significant Accounting Policies

A. Consolidation

The consolidated financial statements include the accounts of all majority-owned subsidiaries of Enron Corp. after the elimination of significant intercompany accounts and transactions. Investments in unconsolidated subsidiaries are accounted for by the equity method.

"Enron" is used from time to time herein as a collective reference to Enron Corp. and its subsidiaries and affiliates. In material respects, the businesses of Enron are conducted by Enron Corp.'s subsidiaries and affiliates whose operations are managed by their respective officers.

Financial statements for prior periods have been restated to reflect the adoption of Statement of Financial Accounting Standards (SFAS) No. 109 (see E below) and the reclassification of EOTT Energy Corp.'s net assets and results of operations to continuing operations (see Note 3).

B. Cash Equivalents
Enron records as cash equivalents all highly liquid short-term investments with original maturities of three months or less.

C. Inventories
Inventories consisting primarily of natural gas in storage of $77.3 million and $116.2 million, crude oil and refined products of $75.5 million and $97.4 million and liquid petroleum products of $37.3 million and $71.7 million at December 31, 1993 and 1992, respectively, are priced at the lower of cost or market.

D. Depreciation, Depletion and Amortization
The provision for depreciation and amortization with respect to operations other than oil and gas producing activities (see below) is computed using the straight-line or Federal Energy Regulatory Commission (FERC) mandated method based on estimated economic lives. Composite depreciation rates are applied to functional groups of property having similar economic characteristics.

Provisions for depreciation, depletion and amortization of proved oil and gas properties are calculated using the units-of-production method. Estimated future dismantlement, restoration and abandonment costs, net of salvage credits, are taken into account in determining depreciation, depletion and amortization.

E. Income Taxes
Enron adopted the provisions of SFAS No. 109 - "Accounting for Income Taxes" effective January 1, 1993 and applied the provisions of the statement retroactively. Enron previously accounted for income taxes under the provisions of SFAS No. 96 which was superceded by SFAS No. 109. SFAS No. 109 retains the asset and liability approach for accounting for income taxes. Under this approach, deferred tax assets and liabilities are recognized based on anticipated future tax consequences attributable to differences between financial statement carrying amounts of assets and liabilities and their respective tax bases. The adoption of SFAS No. 109 did not have a material impact on Enron's results of operations or financial position.

F. Earnings Per Share
Primary earnings per share is computed on the basis of the average number of common shares outstanding during the periods. Common shares held by the Enron Corp. Flexible Equity Trust are not included in the computation of earnings per share (see Note 11). Dilutive common stock equivalents are not material and are not included in the computation of primary earnings per share. Fully diluted earnings per share is computed based upon the average number of common stock and common stock equivalent shares outstanding plus the average number of common shares issuable upon the assumed conversion of convertible securities.

G. Accounting for Price Risk Management Activities
Enron, through its Gas Services Group (EGS), provides price risk management services in the energy sector (these services are further described in Note 2). Enron accounts for these activities using the mark-to-market method of accounting. Under mark-to-market accounting, forwards, swaps, options, futures contracts and other financial instruments with third parties are reflected at market value, net of future servicing costs, with resulting unrealized gains and losses recorded as assets and liabilities from price risk management activities in the Consolidated Balance Sheet. Terms regarding cash settlements of these contracts vary with respect to the actual timing of cash receipts and payments. The amounts shown in the Consolidated Balance Sheet related to price risk management activities also include assets or liabilities which arise as a result of the actual timing of settlements related to these contracts. Current period changes in the assets and liabilities from price risk management activities (resulting primarily from newly originated transactions and the impact of price movements) are recognized as revenues in the Consolidated Income Statement.

The market prices used to value these transactions reflect management's best estimate of market prices considering various factors including closing exchange and over-the-counter quotations, time value and volatility factors underlying the commitments. These market prices are adjusted to reflect the potential impact of liquidating Enron's position in an orderly manner over a reasonable period of time under present market conditions.

Periodically, Enron's other businesses also enter into forwards, futures and other contracts to hedge the impact of market fluctuations on inventories, production or other contractual commitments. Changes in the market value of these transactions are deferred until the gain or loss is recognized on the hedged inventory or commitment. Disclosures regarding the fair value of these financial instruments are included in Note 18.

H. Accounting for Oil and Gas Producing Activities
Enron accounts for oil and gas exploration and production activities under the successful efforts method of accounting. Under such method, oil and gas lease acquisition costs are capitalized when incurred. Unproved properties with significant acquisition costs are assessed quarterly on a property-by-property basis, and any impairment in value is recognized. Unproved properties with acquisition costs that are not individually significant are aggregated, and the portion of such costs estimated to be unproductive based on historical experience and future expected abandonments, is amortized over the average holding period. If the unproved properties are determined to be productive, the appropriate related costs are transferred to proved oil and gas properties. Lease rentals are expensed as incurred.

Oil and gas exploration costs, other than the costs of drilling exploratory wells, are charged to expense as incurred. The costs of drilling exploratory wells are capitalized pending determination of whether the wells have discovered proved commercial reserves. If proved commercial reserves are not discovered, such drilling costs are expensed. The costs of all development wells and related equipment used in the production of crude oil and natural gas are capitalized.

I. Accounting for Sales of Stock by Subsidiary Companies
Enron recognizes gains or losses on sales of stock by its subsidiary companies when such sales are not made as part of a larger plan of corporate reorganization. Such gains or losses are based upon the difference between the book value of Enron's investment in the subsidiary immediately after the sale and the historical book value of Enron's investment immediately prior to the sale.

During August 1992, Enron Oil & Gas Company (EOG) completed a public offering and sale of 4.1 million shares of its common stock, reducing Enron's ownership interest from 84% to 80%. The shares were priced to the public at $28.50 per share and net proceeds from the transaction after underwriting commissions and expenses totaled $111.9 million. A gain in the amount of $59.6 million was recognized by Enron on the transaction. No income tax expense was recorded related to this transaction, consistent with U.S. tax law.

J. Foreign Currency Translation
For subsidiaries whose functional currency is deemed to be other than the U.S. dollar, asset and liability accounts are translated at year-end rates of exchange and revenue and expenses are translated at average exchange rates prevailing during the year. Translation adjustments are included as a separate component of shareholders' equity.

2. Price Risk Management Activities
EGS provides price risk intermediation services to its customers. These services primarily relate to commodities associated with the energy sector (natural gas, crude oil, natural gas liquids), but in some instances also include financial products (interest rates and Canadian dollars). EGS provides these services through a variety of financial instruments including forward contracts involving physical delivery of an energy commodity, swap agreements, which require payments to (or receipt of payments from) counterparties based on the differential between a fixed and variable price for the commodities specified by the contract, options, futures and other contractual arrangements.

Market Risk
EGS's price risk management activities involve offering fixed or known price commitments into the future. These transactions give rise to market risk, which represents the potential loss that can be caused by a change in the market value of a particular commitment. As discussed in Note 1, Enron accounts for these activities at market value. As a result, the impact of changes in market prices are reflected currently in the consolidated financial statements. It is Enron's policy to prohibit speculation on market fluctuations and EGS's objective to maintain a balanced portfolio. However, net open positions often result from the timing of the origination of new transactions. Accordingly, EGS closely monitors and manages its exposure to market risk. Policies are in place which limit the amount of total net exposure and net exposure during any twelve month period for each commodity traded and all traded commodities combined. Procedures exist which allow for real time monitoring of all commitments and positions with daily reporting of positions to senior Enron management. Additionally, sensitivities to changes in market prices of each commodity are examined on a daily basis. Accordingly, Enron does not anticipate a materially adverse effect on financial position or results of operations as a result of market fluctuations.

SFAS No. 105, - "Disclosures of Information about Financial Instruments with Off-Balance-Sheet Risk and Financial Instruments with Concentrations of Credit Risk," requires the disclosure, as set forth below, of the notional amounts of financial instruments that give rise to off-balance-sheet risk. The notional amounts and terms of these agreements, as well as volumetric information regarding EGS's future fixed price commitments, at December 31, 1993 are set forth below (volumes in billions of British thermal units (Bbtus), U.S. dollars in millions):

<TABLE>
<CAPTION>

Product	Fixed Price Payor	Fixed Price Receiver	Maximum Terms in years
<S>	<C>	<C>	<C>
Energy Commodities (Bbtus)			
Swaps	1,715,355	1,480,787	10
Options	269,984	382,098	14
Forwards	795,626	1,195,368	20
Futures	240,971	115,424	3
Financial Products (millions $)			
Interest rate swaps,			
forwards and futures	$ 610	$ 1,028	30
Canadian Dollar			
swaps and futures	289	313	20

</TABLE>

EGS also has sales and purchase commitments associated with contracts based on market prices totaling 4,900,000 Bbtus, with terms extending up to 21 years. The midpoint of EGS's entire portfolio of price risk management activities as of December 31, 1993 was approximately 4.5 years (based on the weighted average value of each transaction).

Credit Risk
Credit risk relates to the risk of loss that Enron would incur as a result of nonperformance by counterparties pursuant to the terms of their contractual obligations. The counterparties associated with EGS's price risk management services as of December 31, 1993 are summarized as follows (amounts in millions):

<TABLE>
<CAPTION>

	Assets from Price Risk Management Activities		
	Investment Grade(a)	Below Investment Grade	Total
<S>	<C>	<C>	<C>
Independent Power Producers	$ 348	$ 17	$ 365
Gas and Electric Utilities	162	22	184
Oil and Gas Producers	380	39	419
Industrials	17	21	38
Financial Institutions	96	-	96
Other	128	40	168
Total	$1,131	$139	1,270
Credit and Other Reserves			103
Assets from Price Risk Management Activities(b)			$1,167

<FN>
(a) After consideration of collateral, which encompass standby letters of credit,parent company guarantees and property interests, including oil and gas reserves.
(b) Three customers' exposures each comprise greater than 5% of assets from price risk management activities.
</TABLE>

This concentration of counterparties may impact EGS's overall exposure to credit risk, either positively or negatively, in that the counterparties may be similarly affected by changes in economic, regulatory or other conditions.

EGS maintains credit policies with regard to its counterparties that management believes significantly minimizes overall credit risk. These policies include a thorough review of potential counterparties' financial condition (including credit rating), collateral requirements under certain circumstances and the use of standardized agreements which allow for the netting of positive and negative exposures associated with a single counterparty.

EGS maintains a credit reserve which is based on management's evaluation of the credit risk of the overall portfolio. This reserve is objectively determined using an implied risk profile based on the difference between risk-free rates of return and each counterparty's cost of borrowing. This implied risk is then used to evaluate the exposure (based on current market value) to each counterparty adjusted for collateral provisions and overall concentration of exposure. Based on EGS's policies, its current exposures and the credit reserve, Enron does not anticipate a materially adverse effect on the financial position or results of operations as a result of counterparty nonperformance.

3. Discontinued Operations Subsequently Retained
During October 1992, the Board of Directors approved a plan to divest all of the crude oil trading and transportation operations of Enron's wholly-owned subsidiary, EOTT Energy Corp. (EOTT), through a spin-off transaction to holders of Enron common stock . As a result, Enron classified these activities as discontinued operations for financial reporting purposes. During the fourth quarter of 1993, Enron's Board of Directors approved a revised plan to divest a majority, but not all, of EOTT through a public offering of limited partnership interests in a master limited partnership.

In January 1994, EOTT Energy Partners, L.P. filed a registration statement with the Securities and Exchange Commission (SEC) to offer common units. Under terms of this offering, Enron will sell substantially all of the business and assets of EOTT to EOTT Energy Partners, L.P., a newly formed limited partnership. Enron will be the general partner and own a substantial interest in EOTT Energy Partners, L.P. after completion of the transaction. Enron reclassified the net assets and results of operations of EOTT, from discontinued operations, for all periods presented. EOTT's total assets and total liabilities as of December 31, 1992, the year it was reported as discontinued operations, were $695.7 million and $598.4 million, respectively. The components of EOTT's net revenues are as follows:

<TABLE>
<CAPTION>

(In Thousands)	1993	1992	1991
<S>	<C>	<C>	<C>
Revenues	$6,358,820	$7,696,734	$8,235,529
Cost of sales	6,231,583	7,605,273	8,102,917
Net revenues	$ 127,237	$ 91,461	$ 132,612

</TABLE>

4. Income Taxes
In August 1993, the U.S. corporate Federal income tax rate increased from 34% to 35% retroactive to January 1, 1993. Under the provisions of SFAS No. 109, the effect of a change in the tax rate is recognized in income for the period of enactment. The principal components of Enron's net deferred income tax liability at December 31, 1993 and 1992 are as follows:

<TABLE>
<CAPTION>

(In Millions)	1993	1992
<S>	<C>	<C>
Deferred income tax assets -		
Alternative minimum tax credit carryforward	$ 219	$ 189
Other	18	28
	237	217
Deferred income tax liabilities -		
Depreciation, depletion and amortization	1,565	1,552
Deferred contract reformation costs	73	107
Other	464	377
	2,102	2,036
Net deferred income tax liabilities*	$1,865	$1,819

<FN>
*Includes $5 million in other current liabilities for 1993 and $60 million in other current assets for 1992.
</TABLE>

The components of income before income taxes and extraordinary items are as follows:

<TABLE>
<CAPTION>

(In Thousands)	1993	1992	1991
<S>	<C>	<C>	<C>
U.S.	$336,445	$337,618	$269,970
Foreign	131,331	81,650	64,630
	$467,776	$419,268	$334,600

</TABLE>

Total income tax expense is summarized as follows:

<TABLE>
<CAPTION>

(In Thousands)	1993	1992	1991
<S>	<C>	<C>	<C>
Payable currently -			
Federal	$ 57,093	$ 78,109	$117,402
State	14,692	13,284	6,074
Foreign	12,269	13,722	21,920
	84,054	105,115	145,396
Payment deferred -			
Federal	(26,070)	(40,361)	(72,214)
State	15,724	13,375	26,909
Foreign	15,369	12,339	2,363
	5,023	(14,647)	(42,942)
	89,077	90,468	102,454
Effect of tax rate increase on deferred tax liability	46,177	-	-
Total Income Tax Expense	$135,254	$ 90,468	$102,454

</TABLE>

The differences between taxes computed at the U.S. Federal statutory rate and Enron's effective rate are as follows:

<TABLE>
<CAPTION>

(In Thousands)	1993	1992	1991
<S>	<C>	<C>	<C>
Statutory Federal income tax provision	$163,722	$142,551	$113,764
Net state income taxes	18,980	17,595	21,769
ESOP dividends	(5,356)	(6,859)	(7,115)
Revision of prior years' tax estimates	(25,000)	(11,200)	(6,351)
Tax rate increase	46,177	-	-
Net operating loss utilization	-	-	(6,656)
Tight gas sands tax credit	(65,172)	(42,500)	(16,926)
Asset and stock sale differences	(21)	(21,324)	-
Other	1,924	12,205	3,969
	$135,254	$ 90,468	$102,454

</TABLE>

Enron has an alternative minimum tax (AMT) credit carryforward of approximately $219 million which can be used to offset regular income taxes payable in future years. The AMT credit has an indefinite carryforward period.

Foreign subsidiaries' cumulative undistributed earnings of approximately $185 million are considered to be indefinitely reinvested outside the U.S. and, accordingly, no U.S. Federal or state income taxes have been provided thereon. In the event of a distribution of those earnings in the form of dividends, Enron may be subject to both foreign withholding taxes and U.S. income taxes, net of allowable foreign tax credits. Determination of any potential amount of unrecognized deferred income tax liability is not practicable.

5. Supplemental Cash Flow Information
Cash paid for income taxes and interest expense is as follows:

<TABLE>
<CAPTION>

(In Thousands)	1993	1992	1991
<S>	<C>	<C>	<C>
Income taxes	$ 39,307	$111,125	$ 74,416
Interest (net of amounts capitalized)	228,034	299,469	284,285

</TABLE>

Non-cash investing and financing activities during 1993 included the exchange of common stock for convertible preferred stock of $33.3 million.

Non-cash investing and financing activities during 1992 included the exchange of common stock for convertible subordinated debentures and convertible preferred stock in transactions valued at $90.5 million and $39.8 million, respectively, and the acquisition of retail gas marketing operations in exchange for common stock valued at $18.3 million. During 1991, non-cash investing and financing activities included the exchange of common stock for convertible subordinated debentures and convertible preferred stock in transactions valued at $10.5 million and $14.9 million, respectively.

Changes in components of working capital are as follows:

<TABLE>
<CAPTION>

(In Thousands)	1993	1992	1991
<S>	<C>	<C>	<C>
Receivables	$(360,206)	$ 118,854	$ 403,840
Inventories	92,228	(22,741)	(15,597)
Payables	144,518	(55,188)	(248,307)

Accrued taxes	(11,941)	(24,690)	50,307
Accrued interest	2,913	(25,088)	13,804
Other	55,975	(148,381)	145,217
Total	$ (76,513)	$(157,234)	$ 349,264

</TABLE>

6. Credit Facilities, Short-Term Borrowings and Long-Term Debt

Enron and EOG have credit facilities with domestic and foreign banks which at December 31, 1993 provided for an aggregate of $1.1 billion in long-term committed credit. Expiration dates of the committed facilities range from December 1994 to January 1997. Interest rates on borrowings are based upon the London Interbank Offered Rate, certificate of deposit rates or other short-term interest rates. Certain credit facilities contain covenants which must be met for Enron to borrow funds. Such debt covenants are not anticipated to materially restrict Enron's ability to borrow funds under such facilities. Compensating balances are not required, but Enron is required to pay a commitment or facility fee. During 1993, no amounts were borrowed under these facilities.

Enron and EOG have also entered into agreements which provide for uncommitted lines of credit totaling $1.06 billion at December 31, 1993. The uncommitted lines have no stated expiration dates. Neither compensating balances nor commitment fees are required as borrowings under the uncommitted credit lines are available subject to agreement by the participating banks. At December 31, 1993, Enron had outstanding $144 million under certain of the uncommitted lines at average interest rates of 3.6%. In addition to borrowing from banks on a short-term basis, Enron and certain of its subsidiaries sell commercial paper to provide short-term financing for various corporate purposes. As of December 31, 1993, 1992 and 1991, short-term borrowings of $143.8 million, $101.0 million, and $243.7 million, respectively, have been reclassified as long-term debt based upon the availability of committed credit facilities with expiration dates exceeding one year and management's intent to maintain such amounts in excess of one year subject to overall reductions in debt levels. Similarly, at December 31, 1993, 1992 and 1991, $132.4 million, $292.3 million, and $289.8 million, respectively, of long-term debt due within one year remained classified as long-term.

Detailed information on short-term borrowings by Enron is as follows:

<TABLE>
<CAPTION>

(Dollars In Millions)	1993	1992	1991
<S>	<C>	<C>	<C>
As of end of year			
Borrowings from -			
Commercial paper	$ -	$ 75.0	$ 189.2
Banks and other	143.8	26.0	54.5
Amount reclassified as long-term debt	(143.8)	(101.0)	(243.7)
Total short-term borrowings	$ -	$ -	$ -
Weighted average interest rate at end of year(a)	3.6%	3.7%	5.5%
For the year ended			
Maximum borrowings at any month end(a)	$1,087.1	$885.5	$ 743.2
Average borrowings(a)(b)	590.9	588.0	500.3
Weighted average interest rate during the year(a)(c)	3.3%	3.9%	6.3%

<FN>
(a) Before reclassification as long-term debt.
(b) Computed using the ending balance at each month end.
(c) Computed using the weighted average interest rates of debt outstanding at each month end.
</TABLE>

Detailed information on long-term debt is as follows:

<TABLE>
<CAPTION>

(In Thousands)	December 31, 1993	1992
<S>	<C>	<C>
Enron Corp.		
Debentures		
6.75% due 2005 - senior subordinated	$ 200,000	$ -
8.25% due 2012 - senior subordinated	150,000	150,000
Notes Payable		
Variable rates	-	10,000
8.15% to 9.25% due from 1994 to 1996	200,000	393,702
9.50% to 10.75% due from 1998 to 2001	342,777	342,777
7.625% to 9.875% due from 2003 to 2006	692,200	692,200
7% due 2023	100,000	-
Other	57,512	10,484
Northern Natural Gas Company		
Notes Payable		
11.00% due 1995	-	88,573
8.00% due 1999	250,000	250,000
6.875% due 2005	100,000	-
Houston Pipe Line Company		
Notes Payable		
12.125% due 1995	100,000	100,000
Other	-	24,062
Transwestern Pipeline Company		
Notes Payable		
7.55% to 9.10% due 2000	123,000	123,000
9.20% due 1998 to 2004	27,000	27,000
Enron Oil & Gas Company		
Notes Payable		
8.92% to 8.98% due 1995	50,000	50,000
9.10% due 1994 to 1998	100,000	100,000
Other	33,000	-
Amount reclassified from short-term debt	143,774	101,007
Unamortized debt discount and premium	(8,023)	(3,881)
Total Long-Term Debt	$2,661,240	$2,458,924

</TABLE>

The aggregate annual maturity requirements applicable to long-term debt outstanding at December 31, 1993 are $132.4 million, $153.4 million, $133.1 million, $22.9 million and $169.0 million for 1994 through 1998, respectively. In addition, based upon available committed credit facilities, $143.8 million of short-term debt which has been reclassified as long-term debt would be due in 1995.

During 1992, Enron retired, pursuant to call provisions, $836 million principal amount of long-term debt with interest rates ranging from 8.7% to 11.5%. The early retirement of debt resulted in extraordinary items of $22.6 million, net of tax.

7. Accounts Receivable

Enron has entered into agreements which provide for the sale of up to $800.0 million of trade accounts receivable with limited recourse provisions. Included in this amount is a $300.0 million agreement which will expire in April 1994 with the remainder expiring in February 1995. At December 31, 1993 and 1992, $700.1 million and $700.0 million, respectively, of receivables were sold under these agreements.

The fees incurred on the sales of accounts receivables totaled $20.6 million, $23.5 million and $37.8 million for 1993, 1992 and 1991, respectively. Additionally, fees incurred in connection with other long-term obligations and the sales of rights to certain recoverable take-or-pay buyout and contract reformation costs totaled $5.1 million, $12.5 million and $30.7 million, respectively, for 1993, 1992 and 1991 and are included in "Interest and Related Charges, net", in the Consolidated Income Statement.

Enron affiliates have concentrations of customers in the electric and gas utility industries. These concentrations of customers may impact Enron's overall exposure to credit risk, either positively or negatively, in that the customers may be similarly affected by changes in economic or other conditions. However, Enron's management believes that the portfolio of receivables is well diversified and that such diversification minimizes any potential credit risk. Credit losses incurred on receivables in these industries compare favorably to losses experienced on Enron's receivables portfolio as a whole. Receivables are generally not collateralized.

8. Production Payment Agreement

In September 1992, EOG entered into a transaction with a limited partnership under which EOG conveyed an interest in approximately 124 billion cubic feet equivalent (136 trillion British thermal units) of natural gas and other hydrocarbons in the Big Piney area of Wyoming for consideration of $326.8 million (the production payment agreement). The natural gas and other hydrocarbons were originally scheduled to be produced and delivered over a period of forty-five months, which period commenced October 1, 1992. Effective October 1, 1993, the agreement was amended providing for the extension of the original term of the volumetric production payment through March 31, 1999 based on a revised schedule of daily quantities of hydrocarbons to be delivered which is approximately one-half of the original schedule. EOG retains responsibility for its working interest share of the cost of operations. Proceeds from the sale were used to repay long-term debt and for other corporate purposes. Enron has accounted for the proceeds received in the transaction as deferred revenue which is being amortized into revenue as natural gas and other hydrocarbons are produced and delivered during the term of the amended agreement. Annual remaining amortization of deferred revenue, based on scheduled deliveries under the amended production payment agreement at December 31, 1993, is approximately $43.3 million per year through 1998 and $10.7 million for 1999. Reserves dedicated to the transaction are included in the estimate of proved oil and gas reserves (see Note 20).

9. Unconsolidated Subsidiaries

Enron has investments in and advances to unconsolidated subsidiaries as follows:

<TABLE>
<CAPTION>

Investee (In Thousands)	Ownership Interest	December 31, 1993	1992
<S>	<C>	<C>	<C>
Citrus Corp.	50%	$169,984	$178,050
Northern Border Pipeline Company	35%	-	207,459
Northern Border Partners, L.P.	13%	55,731	-
Teesside Power Limited	50%	173,915	20,475
Enron/Dominion Cogen Corp.	50%	46,243	49,911
Mojave Pipeline Company	50%	-	42,464
Trailblazer Pipeline Company	33%	25,717	25,538
Oasis Pipe Line Company	25%	7,884	10,140
Madosa	42%	12,894	12,151
Argentina Southern Gas Pipeline System	18%	97,450	23,689
Enron Liquids Pipeline, L.P.	15%	24,036	22,368
Other		83,230	43,817
		$697,084	$636,062

</TABLE>

Enron's equity in earnings (losses) of unconsolidated subsidiaries is as follows:

<TABLE>
<CAPTION>

Investee (In Thousands)	Year Ended December 31, 1993	1992	1991
<S>	<C>	<C>	<C>
Citrus Corp.	$(8,066)	$(11,059)	$(4,601)
Northern Border Pipeline Company	22,934	34,004	24,181
Northern Border Partners, L.P.	1,368	-	-
Teesside Power Limited	12,444	-	-
Enron/Dominion Cogen Corp.	5,703	7,485	6,776
Mojave Pipeline Company	2,435	6,749	11,982
Trailblazer Pipeline Company	3,514	6,687	3,623
Oasis Pipe Line Company	1,299	2,879	5,830

Madosa	5,522	5,873	2,747
Argentina Southern Gas Pipeline System	22,904	-	-
Other	3,236	3,927	4,690
	$73,293	$ 56,545	$55,228

</TABLE>

Summarized combined financial information of Enron's unconsolidated subsidiaries is presented below:

<TABLE>
<CAPTION>

(In Thousands)	December 31, 1993	1992
<S>	<C>	<C>
Balance Sheet		
Current assets	$ 921,850	$1,476,459
Property, plant and equipment, net	4,054,780	4,853,117
Other noncurrent assets	2,330,387	600,060
Current liabilities	982,874	645,981
Noncurrent liabilities	4,584,922	5,174,091
Owners' equity	1,739,221	1,109,564

</TABLE>

<TABLE>
<CAPTION>

(In Thousands)	Year Ended December 31, 1993	1992	1991
<S>	<C>	<C>	<C>
Income Statement			
Operating revenues	$2,351,177	$1,825,158	$1,352,232
Operating expenses	2,016,977	1,528,770	1,064,360
Net income	204,262	122,346	163,886
Distributions Paid to Enron	59,585	42,490	45,973

</TABLE>

Northern Border Partners, L.P. During October 1993, Northern Plains Natural Gas Company, a wholly-owned subsidiary of Enron, along with two of the other three general partners in Northern Border Pipeline Company contributed all of their combined 70% interest in Northern Border to Northern Border Partners, L.P., a Delaware limited partnership (the Partnership), in exchange for general partner interests, subordinated units and common units in the Partnership. Northern Plains sold its common units in the Partnership in an underwritten public offering and received net proceeds of approximately $217 million resulting in a pretax gain of approximately $64 million. Northern Plains retained a 13% interest in the Partnership.

Teesside Power Limited (Teesside). Enron has a 50% ownership interest in Teesside, a joint venture cogeneration company which owns a 1,875 megawatt independent power facility in northeast England. The remaining 50% ownership interest is held by four of the twelve regional electric companies operating in England.

Under the terms of the Shareholder Agreement relating to Teesside, Enron made a capital investment of $151 million on April 1, 1993. An affiliate of Enron operates the facility which was placed in commercial operation on March 27, 1993. Construction revenue and profit have been recognized on the portion of the joint venture not owned by Enron using the percentage of completion method of accounting. Revenue and profit on that portion of the joint venture owned by Enron have been deferred and are being amortized.

Enron has guaranteed the payment of Teesside's obligation in connection with certain grid connection charges which could become due should the power plant terminate operations. Further, Enron has guaranteed the payment of its proportionate share of amounts which could become due in the event of default by Teesside under the terms of the power sales agreements (see Note 16).

Under the terms of certain gas supply agreements extending through 2008, Teesside is obligated to take-or-pay for an average of up to 240 billion British Thermal Units of natural gas per day at indexed prices. Enron has guaranteed 70% of Teesside's payment obligation under the gas supply agreements. However, Enron believes there are alternative markets for such gas should the gas not be taken by Teesside.

Joint Energy Development Investments. In 1993, Joint Energy Development Investments (JEDI), a limited partnership, was formed, comprised of an Enron Subsidiary as general partner and the California Public Employees Retirement System (CalPERS) as limited partner, to acquire energy investments. Enron and CalPERS each own a 50% interest and have each committed to invest $250 million of capital over the next three years in JEDI, $5 million of which has already been contributed as of December 31, 1993. Enron intends to meet its required capital commitments by contributing Enron common stock.

10. Preferred Stock

Convertible Preferred Stock. Each share of the $10.50 Cumulative Second Preferred Convertible Stock is convertible at any time at the option of the holder thereof into 13.652 shares of Enron's common stock, subject to certain adjustments. The Convertible Preferred Stock is currently subject to call at Enron's option at a price of $100 per share plus accrued dividends. Upon involuntary liquidation, holders would be entitled to $100 per share. During 1993, 1992 and 1991, 332,964 shares, 397,710 shares and 148,497 shares, respectively, of the Convertible Preferred Stock were converted into common stock.

Preferred Stock of Subsidiary Company. During November 1993, Enron's wholly-owned subsidiary Enron Capital LLC issued 8.55 million shares of 8% Cumulative Guaranteed Monthly Income Preferred Shares (MIPS) at a price of $25 per share. Net proceeds of approximately $207 million were used by Enron to reduce indebtedness and for other corporate purposes. The MIPS are redeemable at the option of Enron in whole or in part beginning November 1998 at a redemption price of $25 per share plus accumulated and unpaid dividends. Upon liquidation of Enron Capital LLC, the holders of the MIPS are entitled to $25 per share.

11. Common Stock and Dividends

On July 28, 1993, Enron increased the number of authorized shares of common stock from 300,000,000 to 600,000,000 shares and decreased the par value of such common stock from $10.00 to $0.10 per share. The reduced par value of $9.90 for each share outstanding, or $1.18 billion, was transferred to additional paid-in capital. On August 16, 1993, Enron effected, in the form of a stock dividend, a two-for-one common stock split on all issued common stock. The par value of $11.9 million for 119,486,623 additional shares was transferred from additional paid-in capital to common stock. Appropriate references in the financial statements and supplemental financial information to number of shares and related prices, per share amounts and stock option information reflect the stock split.

The dividend history during each of the three years in the period ended December 31, 1993 is as follows: Enron paid quarterly cash dividends on common stock of $.155 per share ($.62 per share annually) until the final quarter of 1991 at which time the dividend was increased to $.1625 per share ($.65 per share annually). The dividend was increased to $.175 per share ($.70 per share annually) for the final quarter of 1992 and was further increased to $.1875 per share ($.75 per share annually) for the final quarter of 1993. Enron's debt agreements do not limit the payment of cash dividends on common stock. Common stock information is as follows:

<TABLE>
<CAPTION>

(In Thousands)	1993(a)	1992	1991
<S>	<C>	<C>	<C>
Common Stock, beginning of year	237,532	103,269	50,625
Issued to Employee Benefit Plans	1,394	11,149	303
Conversions	2,447	3,949	707
Other	156	399	-
Dividend reinvestment	66	-	-
Flexible Equity Trust	7,500	-	-
Stock Split	-	-	51,634
Common Stock, end of year	249,095	118,766	103,269

<FN>
(a) Presented as if the 1993 stock split was January 1, 1993.
</TABLE>

Treasury stock information is as follows:

<TABLE>
<CAPTION>

	1993(d)	1992	1991
<S>	<C>	<C>	<C>
Treasury Stock, beginning of year	349,400	2,050,644	177,755
Employee Benefit Plans			
Issued	(1,435,687)	(1,314,196)	(343,249)
Returned	98,381	15,021	7,754
Open Market Purchases(a)	3,005,200	1,610,100	1,173,800
Conversions(b)	(2,043,090)	(2,205,393)	-
Other(c)	69,404	18,524	9,262
Dividend Reinvestment Plan	(43,608)	-	-
Stock Split	-	-	1,025,322
Treasury Stock, end of year	-	174,700	2,050,644

<FN>
(a) Purchased in connection with a stock repurchase program authorized by the Board of Directors.
(b) Conversions of convertible subordinated debentures in 1992 and convertible preferred stock in 1993.
(c) Purchased pursuant to compensation agreements.
(d) Presented as if the 1993 stock split was January 1, 1993.
</TABLE>

During 1993, Enron issued 130,329,224 shares of its common stock in connection with certain transactions including the two-for-one stock split, the conversion of preferred stock and employee benefit plans.

Enron has various stock option plans (the Plans) under which options for shares of Enron's common stock have been or may be granted to officers, key employees and non-employee members of the Board of Directors. Under the Plans, options granted may be either incentive stock options or nonqualified stock options and are granted at not less than the fair market value of the stock at the time of grant. Expiration dates of the options outstanding at December 31, 1993 range from July 9, 1994 to September 23, 2003. The Plans provide for options to be granted with stock appreciation rights (SAR); however, Enron does not presently intend to issue additional options with an SAR feature. Summarized information for the Plans is as follows:

<TABLE>
<CAPTION>

	1993	1992	1991
<S>	<C>	<C>	<C>
Shares under option, beginning of year	7,314,332	8,996,560	9,406,204
Granted	4,253,233	1,409,480	2,992,000
Exercised	(1,621,680)	(2,807,984)	(2,868,092)
Cancelled or expired	(266,166)	(283,724)	(533,552)
Shares under option, end of year	9,679,719	7,314,332	8,996,560
Shares available for grant at end of year	1,500,301*	5,582,480*	6,954,400*
Shares exercisable at end of year	3,104,722	2,199,224	2,983,784
Average price of options exercised during the year	$13.30	$11.82	$11.05
Average price of options outstanding at end of year	$19.64	$13.47	$12.60

<FN>
*Excludes up to 2,528,560 shares, 2,730,780 shares and 2,750,000 shares as of December 31, 1993, 1992 and 1991, respectively, which may be issued as either Restricted Stock or as stock options.
</TABLE>

Under the Plans, participants may be granted stock without cost to the participant (restricted stock). The shares issued under the Plans vest to the participants at various times ranging from immediate vesting to vesting at the end of a five year period. The following is an analysis of shares of restricted stock:

<TABLE>
<CAPTION>

	1993	1992	1991
<S>	<C>	<C>	<C>
Outstanding at beginning of year	35,588	365,088	223,624
Granted	203,700	19,220	270,080
Cancelled or expired	(3,632)	-	(9,840)
Issued	(13,998)	(348,720)	(118,776)
Outstanding at end of year	221,658	35,588	365,088
Available for grant at end of year	2,528,560	2,730,780	2,750,000
Average price per share on date of grant	$27.50	$11.18	$11.08

</TABLE>

Flexible Equity Trust (the Trust). In December 1993, Enron established the Trust to fund a portion of its obligations arising from its various employee compensation and benefit plans. Enron issued 7.5 million shares of common stock to the Trust in exchange for cash and an interest bearing promissory note. The note held by Enron is reflected as a reduction of "Other" shareholders' equity. Common shares held by the Trust are not included in the computation of earnings per share.

12. Retirement Benefits Plan and ESOP

Enron maintains a retirement plan (the Enron Plan) which is a noncontributory defined benefit plan covering substantially all employees in the United States and certain employees in foreign countries. Participants in the Enron Plan with five years or more of service are entitled to retirement benefits based on a formula that uses a percentage of final average pay and years of service. Enron maintains a noncontributory employee stock ownership plan (ESOP) which covers all eligible employees. Allocations to individual employees' retirement accounts within the ESOP offset a portion of benefits earned under the Enron Plan. To the extent allocations to the individual employees retirement account within the ESOP exceed accrued benefits under the Enron Plan at the date of retirement, the individual employees receive the additional shares.

The components of pension expense are as follows:

<TABLE>
<CAPTION>

(In Thousands)	1993	1992	1991
<S>	<C>	<C>	<C>
Service cost - benefits earned during the year	$ 11,709	$ 10,224	$ 7,960
Interest cost on projected benefit obligation	25,230	22,699	20,008
Actual return on plan assets	(37,507)	(52,141)	(43,092)
Amortization and deferrals	11,184	28,897	21,775
Early retirement termination benefits	-	166	-
Pension expense	$ 10,616	$ 9,845	$ 6,651

</TABLE>

The valuation date of the Enron Plan and the ESOP is September 30. The funded status as of the valuation date of the Enron Plan and the ESOP reconciles with the amount detailed below which is included in other assets on the Consolidated Balance Sheet at December 31, 1993 and 1992. Assets of the ESOP offset retirement benefits accrued under the Enron Plan only to the extent allocated to individual employee retirement accounts.

<TABLE>
<CAPTION>

(In Thousands)	1993	1992
<S>	<C>	<C>
Actuarial present value of accumulated benefit obligation at September 30		
Vested	$(284,559)	$(204,176)
Nonvested	(27,862)	(15,696)
Additional amounts related to projected wage increases	(66,641)	(65,796)
Projected benefit obligation	(379,062)	(285,668)
Plan assets at fair value(a)	404,397	300,755
Projected benefit obligation less than Plan assets	25,335	15,087
Unrecognized net loss	29,690	51,762
Unrecognized prior service cost	14,113	15,810
Unrecognized net asset at transition	(48,272)	(56,634)
Contributions	815	2,004
Prepaid pension cost at December 31	$ 21,681	$ 28,029
Discount rate	7.00%	9.00%
Long-term rate of return on assets	10.50	10.50
Rate of increase in wages	4.00	5.00

<FN>
(a) Includes plan assets of the ESOP of $286,041 and $193,144 for the years 1993 and 1992, respectively.
</TABLE>

Assets of the Enron Plan are comprised primarily of equity securities, fixed income securities and temporary cash investments. It is Enron's policy to fund all pension costs accrued to the minimum amount required by federal tax regulations.

13. Postretirement Benefits Other Than Pensions

Enron provides certain medical, life insurance and dental benefits to eligible employees who retire under the Enron Retirement Plan and their eligible surviving spouses. Benefits are provided under the provisions of a contributory defined dollar benefit plan. Enron is currently funding that portion of its obligations under its postretirement benefit plan which is expected to be recoverable through rates by its regulated pipelines.

Effective January 1, 1993, Enron adopted the provisions of SFAS No. 106 - "Employers Accounting for Postretirement Benefits Other Than Pensions". SFAS No. 106 requires that employers providing postretirement benefits accrue those costs over the service lives of the employees expected to be eligible to receive such benefits. Enron has elected the prospective transition approach and is amortizing the transition obligation which existed at January 1, 1993 over a period of approximately 19 years.

The following table sets forth the plan's funded status reconciled with the amounts reported in the Consolidated Balance Sheet.

<TABLE>
<CAPTION>

(In Thousands)	1993
<S>	<C>
Actuarial present value of accumulated postretirement benefit obligation (APBO)	
Retirees	$ (93,101)
Fully eligible active plan participants	(2,748)
Other employees	(21,611)
Total APBO	(117,460)
Plan assets at fair value	1,938
Accumulated postretirement benefit obligation in excess of plan assets	(115,522)
Unrecognized transition obligation	79,547
Unrecognized prior service costs	19,297
Unrecognized net loss	14,249
Accrued postretirement benefit obligation	$ (2,429)

</TABLE>

The components of net periodic postretirement benefit expenses are as follows:

<TABLE>
<CAPTION>

(In Thousands)	1993
<S>	<C>
Service costs	$ 850
Interest costs	7,374
Return on plan assets	(39)
Amortization of transition obligation	4,744
Postretirement benefit expense	$12,929

</TABLE>

The measurement of the APBO assumes a 7% discount rate and a health care cost trend rate of 13% in 1993 decreasing to 5% by the year 2005 and beyond. A 1% increase in the health care cost trend rate would have the effect of increasing the APBO and the net periodic expense by approximately $9.7 million and $0.6 million, respectively.

14. Natural Gas Rates and Regulatory Issues

Regulatory issues on Enron's regulated pipelines are subject to final determination by the FERC. Enron has provided a reserve related to pending regulatory issues and believes that the ultimate resolution of such issues will not have a materially adverse impact on Enron's financial position or results of operations.

The regulated pipelines have all successfully completed their transitions under FERC Order 636 (currently under appeal before the U.S. Court of Appeals for the 11th Circuit), and have completely unbundled their sales services from their transportation services. As required by Order 636, each of the regulated pipelines has implemented a straight fixed variable rate design which provides that all fixed costs to firm customers including return on equity, are to be received through fixed monthly demand or capacity reservation charges which are not a function of volumes transported.

Under their respective restructuring orders, the regulated pipelines are entitled to recover FERC Order 636 transition costs from customers. Transition costs incurred of $168 million have been deferred pending recovery from customers over varying time periods, generally of up to five years. Future transition costs are subject to ongoing negotiations and market factors. Enron believes that the ultimate resolution of FERC Order 636 transition costs will not have a material impact on Enron's financial position or results of operations.

15. Litigation and Other Contingencies

Enron is party to various claims and litigation, the significant items of which are discussed below. Although no assurances can be given, Enron believes, based on its experience to date and after considering appropriate reserves that have been established, that the ultimate resolution of such items, individually or in the aggregate, will not have a materially adverse impact on Enron's financial position or results of operations.

Litigation

TransAmerican Natural Gas Corporation (TransAmerican) has filed a petition against Enron Corp. and EOG alleging breach of confidentiality agreements, misappropriation of trade secrets and unfair competition, with specific reference to four tracts in Webb County, Texas, which EOG leased for their oil and gas exploration and development potential. TransAmerican seeks actual damages of $100 million and exemplary damages of $300 million. EOG has filed claims against TransAmerican and its sole shareholder alleging fraud, land fraud, negligent misrepresentation and breach of state antitrust laws. Trial is set for May 2, 1994. Although no assurances can be given, Enron believes that TransAmerican's claims are without merit and that the ultimate resolution of this matter will not have a materially adverse effect on its financial position or results of operations.

A pipeline company in which an Enron affiliate has a minority interest and for which an Enron affiliate has served as operator, has filed a petition against Enron and certain affiliates alleging an unspecified amount of damages relating to the operation of such pipeline company. Based upon information currently available, it is not possible to predict the outcome of such litigation; however, Enron believes that the results will not have a materially adverse effect on Enron's financial position or results of operations.

Like other companies in the natural gas industry, Enron has certain gas purchase contracts which provide for take-or-pay obligations and fixed prices. Certain suppliers have made claims, either formally or informally, for payment under take-or-pay provisions. At December 31, 1993, amounts of pending take-or-pay claims and litigation are not material.

Peruvian Operations
During 1985, the Peruvian government unilaterally cancelled certain exploration and production agreements between the government-owned oil company and Belco Petroleum Corporation of Peru (BPCP), a wholly-owned subsidiary of Enron, and subsequently nationalized the operations of BPCP. Enron filed claims with its insurers in connection with the nationalization and in February 1989, the insurers paid Enron approximately $162 million. On September 21, 1993, the Peruvian government signed a settlement agreement with American International Group, Inc. and BPCP which will allow Enron to recover its remaining investment of approximately $33 million.

Environmental Matters
Enron is subject to extensive Federal, state and local environmental laws and regulations. These laws and regulations require expenditures in connection with the construction of new facilities, the operation of existing facilities and for remediation at various operating sites. The implementation of the Clean Air Act Amendments is expected to result in increased operating expenditures. These increased operating expenses are not expected to have a material impact on Enron's financial position or results of operations.

In addition, Enron received requests for information from the Environmental Protection Agency (EPA) and state environmental agencies inquiring whether Enron has disposed of materials at certain waste disposal sites. Enron has received notices from EPA and state agencies that it is a "potentially responsible party" (PRP) under the Comprehensive Environmental Response, Compensation and Liability Act and analogous state statutes, and may be required to share in the costs of the cleanup of other, similar sites. However, management does not believe that any potential assessments in connection with these PRP notices and third party claims, either taken individually or in the aggregate, will have a material impact on Enron's financial position or results of operations.

16. Commitments
Firm Transportation Obligations
Enron has firm transportation agreements with various joint ventures. Under these agreements, Enron must make specified minimum payments each month. The estimated aggregate amounts of such required future payments at December 31, 1993, were:

<TABLE>
<CAPTION>
(In Millions)

<C>	<C>
1994	$ 40.2
1995	40.1
1996	108.2
1997	117.2
1998	118.9
Later years	1,240.0
Total	$1,664.6

</TABLE>

The costs incurred under these agreements, including commodity charges on actual quantities shipped, totaled $38.2 million, $42.7 million and $53.8 million in 1993, 1992 and 1991, respectively. Enron has assigned a firm transportation contract with one of its joint venture pipelines to a third party and guaranteed minimum payments under the contract averaging approximately $43 million annually through 2001.

Other Commitments
Enron leases property, operating facilities and equipment under various operating leases, certain of which contain renewal and purchase options and residual value guarantees. Guarantees under the leases total $955 million at December 31, 1993.

During July 1992, Enron modified and extended an agreement entered into in 1988 for a substantial amount of data processing facilities management services. The modification extends the original 10 year agreement for a period of three years through 2001. As part of the agreement, Enron prepaid $150 million for certain services to be performed over the life of the agreement.

Future commitments related to these items at December 31, 1993 are as follows:

<TABLE>
<CAPTION>
(In Millions)

<C>	<C>
1994	$ 194.1
1995	243.4
1996	334.9
1997	114.3
1998	105.3
Later years	650.3
Total minimum payments	$1,642.3

</TABLE>

Total rent expense incurred during 1993, 1992 and 1991 was $104.1 million, $64.7 million and $85.9 million, respectively.

Enron guarantees certain long-term contracts for the sale of electrical power and steam from the Texas City cogeneration facility owned by one of Enron's equity investees. Under terms of the contracts, which initially extend through June 1999, Enron could be liable for penalties should, under certain conditions, the contracts be terminated early. Enron also guarantees the performance of certain of its subsidiaries in connection with letters of credit issued on behalf of those subsidiaries. At December 31, 1993, a total of $124 million of such guarantees were outstanding. Management does not expect to incur any material liabilities as a result of these obligations. In addition, Enron is a guarantor on certain debt of unconsolidated joint ventures and unconsolidated subsidiaries and other companies totaling approximately $305 million. Management does not consider it likely that there would be any losses associated with these guarantees. In addition, certain commitments have been made related to 1994 planned capital expenditures.

17. Other Income, Net
The components of Other Income, Net are as follows:

<TABLE>
<CAPTION>

	Year Ended December 31,		
(In Thousands)	1993	1992	1991
<S>	<C>	<C>	<C>
Gains on sales of Mobil stock	$ -	$ 52,048	$27,944
Gains on sales of oil and gas properties	13,318	6,037	14,983
Gains on sales of other assets and investments	102,268	18,549	15,426
Regulatory, contingency and other adjustments	(55,689)	(40,927)	11,036
Litigation adjustments and settlements, net	4,282	(41,870)	27,086
Other	11,254	(10,210)	9,611
	$75,433	$(16,373)	$106,086

</TABLE>

18. Financial Instruments
The following disclosures on the estimated fair value of financial instruments are presented in accordance with the requirements of SFAS No. 107 - "Disclosures About Fair Value of Financial Instruments." Fair value as used in SFAS No. 107 represents the amount at which the instrument could be exchanged in a current transaction between willing parties. The estimated fair value amounts have been determined by Enron using available market data and valuation methodologies. Judgement is necessarily required in interpreting market data and the use of different market assumptions or estimation methodologies may affect the estimated fair value amounts. The amounts disclosed below exclude Enron's price risk management activities discussed in Notes 1 and 2.

<TABLE>
<CAPTION>

	December 31, 1993		December 31, 1992	
(In Millions)	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
<S>	<C>	<C>	<C>	<C>
Balance Sheet Financial Instruments				
Long-term debt	$2,661.2	$2,903.4	$2,458.9	$2,603.0
Other Financial Instruments				
Interest rate swap agreements	-	(2.3)	-	(4.8)
Foreign currency contracts	-	(0.1)	-	0.3
Guarantees	-	(2.7)	-	(9.3)

</TABLE>

Long-Term Debt. The fair market value of long-term debt is the estimated cost to acquire the debt, including a premium or discount for the differential between the issue rate and the year-end market rate. The fair value of long-term debt is based upon quoted market prices and, where such prices are not available, upon interest rates available to Enron.

Interest Rate Swap Agreements. Enron and EOG have entered into various interest rate swap transactions to hedge certain floating interest rate exposure in 1993 and 1994. This floating interest rate exposure arises primarily from short-term interest bearing debt as well as certain operating lease obligations and accounts receivable sales for which payments are subject to floating interest rates (see Notes 6, 7 and 16).

At December 31, 1993, Enron and EOG had outstanding interest rate swap agreements with a notional principal amount of $3.6 billion. During January 1994, Enron executed additional swap agreements with notional principal amounts totaling $700 million. Included in the $4.3 billion total swap agreements is $2.1 billion notional principal amount of interest rate swap agreements which expired subsequent to December 31, 1993 and which were executed to hedge anticipated floating rate exposure in 1993. Also included are approximately $2.1 billion notional principal amount of interest rate swap agreements executed to hedge anticipated floating rate exposure in 1994. The remaining notional principal amounts include swap agreements extending beyond 1994. The fair value of interest rate swap agreements is based upon termination values obtained from third parties.

Credit Risk. While notional contract amounts are used to express the volume of interest rate swap agreements, the amounts potentially subject to credit risk, in the event of nonperformance by the third parties, are substantially smaller. Enron does not anticipate any material impact to its financial position or results of operations as a result of nonperformance by the third parties.

Price Risk Management. Enron entered into certain price swap agreements to, in effect, hedge the market risk caused by fluctuations in the price of natural gas. The agreements call for Enron to make payments to (or receive payments from) the other party based upon the differential between a fixed and a variable price for natural gas as specified by the contract. The current swap agreements run for periods of ten years and have a notional contract amount of approximately $299 million at December 31, 1993.

Foreign Currency Contracts. Foreign currency contracts are entered into to hedge currency exposure from commercial transactions. At December 31, 1993, foreign currency contracts with a principal amount of $38.3 million were outstanding. Fair value of such contracts are based upon year-end fair market values.

Guarantees. As more fully discussed in Notes 9 and 16, Enron is a guarantor on certain debt and lease obligations. The fair value of such guarantees is based upon Enron's estimation of the cost of securing third party letters of credit equal to Enron's obligations under such guarantees.

19. Business and Geographic Segment Information
Enron's operations are classified into five business segments:

Transportation and Operation - Transmission of natural gas. Construction, management and operation of pipelines, liquids plants and power facilities. Crude oil transportation activities and investment in liquids pipeline operations.

Gas Services - Purchasing, marketing and financing of natural gas, natural gas liquids and power. Price risk management in connection with natural gas and natural gas liquids transactions. Intrastate natural gas pipelines. Development, acquisition and promotion of natural gas fired power plants in North America.

Gas Processing - Extraction of natural gas liquids in North America.

International Gas and Power Services - Independent (non-utility) development, acquisition and promotion of natural gas fired power plants, natural gas liquids facilities and pipelines outside of North America. International marketing of natural gas liquids.

Exploration and Production - Natural gas and crude oil exploration and production primarily in the United States, Canada and Trinidad.

Enron's business segment information has been reclassified from prior years to reflect the realignment of Enron's operations. Financial information by business and geographic segment for each of the three years in the period ended December 31, 1993, is presented below.

Operations In Business and Geographic Segments
Business Segments
<TABLE>
<CAPTION>

(In Thousands)	Transportation and Operation	Gas Services	Gas Processing	International Gas and Power Services	Exploration and Production	Corporate and Other(c)(d)	Total
<S>	<C>	<C>	<C>	<C>	<C>	<C>	<C>
1993							
Unaffiliated Revenues(a)	$1,385,925	$5,392,121	$ 57,825	$ 751,375	$ 385,236	$ -	$ 7,972,482
Intersegment Revenues(b)	80,081	243,646	386,976	19,213	301,691	(1,031,607)	-
Total Revenues	1,466,006	5,635,767	444,801	770,588	686,927	(1,031,607)	7,972,482
Depreciation, Depletion and Amortization	115,922	74,677	6,283	9,081	249,704	2,521	458,188
Operating Income (Loss)	341,272	149,886	5,687	64,582	102,241	(46,184)	617,484
Equity in Earnings of Unconsolidated Subsidiaries	22,427	8,821	-	41,962	-	83	73,293
Other Income, net	18,437	10,115	22,351	24,835	19,953	11,199	106,890
Income Before Interest, Minority Interest and Income Taxes	382,136	168,822	28,038	131,379	122,194	(34,902)	797,667
Additions to Property, Plant and Equipment	144,835	78,453	24,065	52,545	383,064	5,070	688,032
Identifiable Assets	2,808,816	5,165,809	186,354	492,297	1,668,395	485,560	10,807,231
Investments in and Advances to Unconsolidated Subsidiaries	278,912	83,360	-	315,461	-	19,351	697,084
Total Assets	$3,087,728	$5,249,169	$186,354	$ 807,758	$1,668,395	$ 504,911	$11,504,315
1992							
Unaffiliated Revenues(a)	$1,418,761	$3,806,088	$65,980	$ 864,695	$ 253,749	$ -	$ 6,409,273
Intersegment Revenues(b)	82,513	152,371	361,043	10,529	300,375	(906,831)	-
Total Revenues	1,501,274	958,459	427,023	875,224	554,124	(906,831)	409,273
Depreciation, Depletion and Amortization	111,141	70,438	6,283	6,897	179,839	1,421	376,019
Operating Income (Loss)	314,412	160,167	54,132	(4,502)	99,572	(10,009)	613,772
Equity in Earnings of Unconsolidated Subsidiaries	36,628	12,391	1,926	5,505	-	95	56,545
Other Income, net	27,267	(26,012)	(211)	32,074	2,561	61,186	96,865
Income Before Interest, Minority Interest and Income Taxes	378,307	146,546	55,847	33,077	102,133	51,272	767,182
Additions to Property, Plant and Equipment	144,468	33,584	34,211	10,236	362,403	11,983	596,885
Identifiable Assets	2,420,053	4,085,861	222,727	388,248	1,563,136	995,516	9,675,541
Investments in and Advances to Unconsolidated Subsidiaries	479,246	75,483	-	79,991	-	1,342	636,062
Total Assets	$2,899,299	$4,161,344	$222,727	$ 468,239	$1,563,136	$ 996,858	$10,311,603
1991							
Unaffiliated Revenues(a)	$1,519,147	$2,901,382	$ 67,250	$1,022,998	$ 172,164	$ -	$ 5,682,941
Intersegment Revenues(b)	109,930	81,311	329,230	7,778	297,878	(826,127)	-
Total Revenues	1,629,077	2,982,693	396,480	1,030,776	470,042	(826,127)	5,682,941
Depreciation, Depletion and Amortization	108,922	85,342	5,377	4,648	160,885	783	365,957
Operating Income (Loss)	275,013	56,994	91,534	40,117	63,401	(29,122)	497,937
Equity in Earnings of Unconsolidated Subsidiaries	37,000	13,355	-	4,643	-	230	55,228
Other Income, net	31,393	765	2,636	24,075	11,768	91,500	162,137
Income Before Interest, Minority Interest and Income Taxes	343,406	71,114	94,170	68,835	75,169	62,608	715,302
Additions to Property, Plant and Equipment	368,756	40,849	43,216	7,934	211,673	34,655	707,083
Identifiable Assets	2,682,546	3,763,396	265,636	346,494	1,410,244	1,043,327	9,511,643
Investments in and Advances to Unconsolidated Subsidiaries	502,737	33,625	-	20,280	-	1,385	558,027
Total Assets	$3,185,283	$3,797,021	$265,636	$ 366,774	$1,410,244	$1,044,712	$10,069,670

<FN>
(a) Unaffiliated revenues include sales to unconsolidated subsidiaries.
(b) Intersegment sales are made at prices comparable to those received from unaffiliated customers and in some instances are affected by regulatory considerations.
(c) Corporate and Other assets consist of cash and cash equivalents, investments in marketable securities, receivables transferred from subsidiaries in connection with the receivables sale program and miscellaneous other assets.
(d) Includes consolidating eliminations.
</TABLE>

Geographic Segments
<TABLE>
<CAPTION>

(In Thousands)	Year Ended December 31, 1993	1992	1991
<S>	<C>	<C>	<C>
Operating Revenues from Unaffiliated Customers			
United States	$ 7,058,088	$5,515,600	$4,644,267
Foreign	914,394	893,673	1,038,674
	$ 7,972,482	$6,409,273	$5,682,941
Intersegment Sales			
United States	$ 20,785	$ 54,498	$ 267,119
Foreign	66,574	24,108	23,545
	$ 87,359	$ 78,606	$ 290,664
Operating Income			
United States	$ 553,956	$ 628,542	$ 471,091
Foreign	63,528	(14,770)	26,846
	$ 617,484	$ 613,772	$ 497,937
Income Before Interest, Minority Interest and Taxes			
United States	$ 663,276	$ 743,623	$ 656,169
Foreign	134,391	23,559	59,133
	$ 797,667	$ 767,182	$ 715,302
Identifiable Assets			
United States	$ 9,939,618	$8,982,307	$8,855,302
Foreign	867,613	693,234	656,341
	$10,807,231	$9,675,541	$9,511,643

</TABLE>

20. Oil and Gas Producing Activities
The following information regarding Enron's oil and gas producing activities should be read in conjunction with Note 1.
Capitalized Costs Relating to Oil and Gas Producing Activities

<TABLE>
<CAPTION>

(In Thousands)	December 31, 1993	1992
<S>	<C>	<C>
Proved properties	$2,675,419	$2,396,601
Unproved properties	96,801	78,770
	2,772,220	2,475,371
Accumulated depreciation, depletion and amortization	(1,226,175)	(1,007,360)
Net capitalized costs	$1,546,045	$1,468,011

</TABLE>

Costs Incurred in Oil and Gas Property Acquisition, Exploration and Development Activities(a)

<TABLE>
<CAPTION>

(In Thousands)	United States	Foreign Canada	Foreign Other	Total
<S>	<C>	<C>	<C>	<C>
1993				
Acquisition of properties				
Unproved	$ 23,686	$ 4,556	$ 887	$ 29,129
Proved	6,625	2,598	-	9,223
Total	30,311	7,154	887	38,352
Exploration	53,918	9,096	19,439	82,453
Development	247,705	28,045	41,785	317,535
Total	$331,934	$44,295	$62,111	$438,340
1992				
Acquisition of properties				
Unproved	$ 21,844	$ 1,173	$ 3	$ 23,020
Proved	25,958	39,281	-	65,239
Total	47,802	40,454	3	88,259
Exploration	38,547	5,787	11,141	55,475
Development	256,814	5,162	735	262,711
Total	$343,163	$51,403	$11,879	$406,445
1991				
Acquisition of properties				
Unproved	$12,156	$ 223	$ 176	$ 12,555
Proved	40,039	2,362	-	42,401
Total	52,195	2,585	176	54,956
Exploration	39,916	5,369	15,062	60,347
Development	132,200	10,338	-	142,538
Total	$224,311	$18,292	$15,238	$257,841

<FN>
(a) Costs have been categorized on the basis of Financial Accounting Standards Board definitions which include costs of oil and gas producing activities whether capitalized or charged to expense as incurred.
</TABLE>

Results of Operations for Oil and Gas Producing Activities(a)

The following tables set forth results of operations for oil and gas producing activities for the three years in the period ended December 31, 1993:

<TABLE>
<CAPTION>

(In Thousands)	United States	Foreign Canada	Foreign Other	Total
<S>	<C>	<C>	<C>	<C>
1993				
Operating Revenues				
Associated Companies	$369,824	$ 9,637	$ -	$379,461
Trade	140,552	33,228	1,209	174,989
Total	510,376	42,865	1,209	554,450
Exploration expenses, including dry hole costs	35,029	6,657	13,590	55,276
Production costs	75,767	14,063	1,496	91,326
Impairment of unproved				

oil and gas properties	19,499	968	-	20,467
Depreciation, depletion and amortization	234,292	14,630	541	249,463
Income (loss) before income taxes	145,789	6,547	(14,418)	137,918
Income tax expense (benefit)	(20,329)	2,447	(2,762)	(20,644)
Results of Operations	$166,118	$ 4,100	$(11,656)	$158,562
1992				
Operating Revenues				
Associated Companies	$251,649	$10,074	$ -	$261,723
Trade	106,633	19,313	-	125,946
Total	358,282	29,387	-	387,669
Exploration expenses, including dry hole costs	29,705	3,829	10,508	44,042
Production costs	63,571	9,271	-	72,842
Impairment of unproved oil and gas properties	12,001	1,034	2,101	15,136
Depreciation, depletion and amortization	167,767	11,719	327	179,813
Income (loss) before income taxes	85,238	3,534	(12,936)	75,836
Income tax expense (benefit)	(16,030)	1,202	(4,398)	(19,226)
Results of Operations	$101,268	$ 2,332	$(8,538)	$ 95,062
1991 (Restated)				
Operating Revenues				
Associated Companies	$197,841	$10,244	$ -	$208,085
Trade	78,964	19,004	-	97,968
Total	276,805	29,248	-	306,053
Exploration expenses, including dry hole costs	28,107	3,659	14,402	46,168
Production costs	56,167	9,418	-	65,585
Impairment of unproved oil and gas properties	10,342	2,449	-	12,791
Depreciation, depletion and amortization	148,401	12,385	99	160,885
Income (loss) before income taxes	33,788	1,337	(14,501)	20,624
Income tax expense (benefit)	(5,076)	455	(4,930)	(9,551)
Results of Operations	$38,864	$ 882	$ (9,571)	$ 30,175

<FN>
(a) Excludes net revenues associated with other marketing activities, interest charges, general corporate expenses and certain gathering and handling fees for each of the three years in the period ended December 31, 1993. The gathering and handling fees and other marketing net revenues are directly associated with oil and gas operations with regard to required segment reporting, but are not part of required disclosures about oil and gas producing activities.
</TABLE>

Oil and Gas Reserve Information (Unaudited)
The following summarizes the policies used by Enron in preparing the accompanying oil and gas supplemental reserve disclosures, Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves and reconciliation of such standardized measure from period to period.

Estimates of proved and proved developed reserves at December 31, 1993, 1992 and 1991 were based on studies performed by Enron's engineering staff for reserves in the United States, Canada and Trinidad. Opinions by DeGolyer and MacNaughton, independent petroleum consultants, for the years ended December 31, 1993, 1992 and 1991 covering producing areas containing 65%, 69% and 73%, respectively, of proved reserves of Enron on a net-equivalent-cubic-feet-of-gas basis, indicate that the estimates of proved reserves prepared by Enron's engineering staff for the properties reviewed by DeGolyer and MacNaughton, when compared in total on a net-equivalent-cubic-feet-of-gas basis, do not differ by more than 5% from those prepared by DeGolyer and MacNaughton's engineering staff. All reports by DeGolyer and MacNaughton were developed utilizing geological and engineering data provided by Enron.

The standardized measure of discounted future net cash flows does not purport, nor should it be interpreted, to present the fair market value of Enron's crude oil and natural gas reserves. An estimate of fair value would also take into account, among other things, the recovery of reserves not presently classified as proved reserves, anticipated future changes in prices and costs and a discount factor more representative of the time value of money and the risks inherent in reserve estimates.

Standardized Measure of Discounted Future
Net Cash Flows Relating to Proved
Oil and Gas Reserves(a)

<TABLE>
<CAPTION>

(In Thousands)	United States	Canada	Trinidad	Total
<S>	<C>	<C>	<C>	<C>
1993				
Future revenues(b)	$3,343,900(d)	$592,845	$147,542	$4,084,287(d)
Future production costs	(639,760)	(230,230)	(45,385)	(915,375)
Future development costs	(165,473)	(21,001)	(7,582)	(194,056)
Future net cash flows before income taxes	2,538,667	341,614	94,575	2,974,856
Discount to present value at 10% annual rate	(951,748)	(143,992)	(20,097)	(1,115,837)
Present value of future net cash flows before income taxes	1,586,919	197,622	74,478	1,859,019
Future income taxes discounted at 10% annual rate(c)	(219,228)	(37,851)	(24,899)	(281,978)
Standardized measure of discounted future net cash flows relating to proved oil and gas reserves(b)	$1,367,691(e)	$159,771	$ 49,579	$1,577,041(e)
1992				
Future revenues(b)	$3,017,188(d)	$363,284	$ -	$3,380,472(d)
Future production costs	(573,763)	(105,802)	-	(679,565)
Future development costs	(194,246)	(12,881)	-	(207,127)
Future net cash flows before income taxes	2,249,179	244,601	-	2,493,780
Discount to present value at 10% annual rate	(790,027)	(91,126)	-	(881,153)
Present value of future net cash flows before income taxes	1,459,152	153,475	-	1,612,627
Future income taxes discounted at 10% annual rate(c)	(147,736)	(28,056)	-	(175,792)
Standardized measure of discounted future net cash flows relating to proved oil and gas reserves(b)	$1,311,416(e)	$125,419	$ -	$1,436,835(e)
1991				
Future revenues(b)	$2,501,439	$269,917	$ -	$2,771,356
Future production costs	(504,420)	(79,413)	-	(583,833)
Future development costs	(189,091)	(6,132)	-	(195,223)
Future net cash flows before income taxes	1,807,928	184,372	-	1,992,300
Discount to present value at 10% annual rate	(618,919)	(62,137)	-	(681,056)
Present value of future net cash flows before income taxes	1,189,009	122,235	-	1,311,244
Future income taxes discounted at 10% annual rate(c)	(127,188)	(27,979)	-	(155,167)
Standardized measure of discounted future net cash flows relating to proved oil and gas reserves(b)	$1,061,821	$ 94,256	$ -	$1,156,077

<FN>
(a) Includes amounts attributable to a 20% minority interest at December 31, 1993 and 1992 and a 16% minority interest at December 31, 1991.
(b) Based on year-end market prices determined at the point of delivery from the producing unit.
(c) Future income taxes before discount were $540.3 million U.S., $91.7 million Canada and $35.5 million Trinidad, $394.1 million U.S. and $63.0 million Canada and $279.4 million U.S. and $53.0 million Canada for the years ended December 31, 1993, 1992 and 1991, respectively.
(d) "Future revenues" includes approximately $189.1 million ($146.9 million discounted at 10% annual rate for 1993) and $203.5 million ($174.5 million discounted at 10% annual rate for 1992) related to volumes associated with a volumetric production payment sold effective October 1, 1992, as amended, to be delivered over a seventy-eight month period which period commenced October 1, 1992 (see Note 8).
(e) Includes approximately $92.6 million in 1993 and $111.2 million in 1992 representing the discounted present value at a discount rate of 10% of the "future revenues" detailed in Note (d) after deducting future income taxes.
</TABLE>

Changes in Standardized Measure of
Discounted Future Net Cash Flows

<TABLE>
<CAPTION>

(In Thousands)	United States	Canada	Trinidad	Total
<S>	<C>	<C>	<C>	<C>
December 31, 1990	$ 928,584	$130,742	$ -	$1,059,326
Sales and transfers of oil and gas produced, net of production costs	(220,638)	(19,830)	-	(240,468)
Net changes in prices and production costs	(150,061)	(51,609)	-	(201,670)
Extensions, discoveries, additions and improved recovery, net of related costs	212,097	4,802	-	216,899
Development costs incurred	36,719	11	-	36,730
Revisions of estimated development costs	1,640	2,833	-	4,473
Revisions of previous quantity estimates	37,535	1,178	-	38,713
Accretion of discount	116,559	17,823	-	134,382
Net change in income taxes	109,821	19,512	-	129,333
Purchases of reserves in place	38,350	(558)	-	37,792
Sales of reserves in place	(17,321)	(2,328)	-	(19,649)
Changes in timing and other	(31,464)	(8,320)	-	(39,784)
December 31, 1991	1,061,821	94,256	-	1,156,077
Sales and transfers of oil and gas produced, net of production costs	(294,711)	(20,116)	-	(314,827)
Net changes in prices and production costs	257,572	8,190	-	265,762
Extensions, discoveries, additions and improved recovery, net of related costs	275,231	8,999	-	284,230
Development costs incurred	49,668	177	-	49,845
Revisions of estimated development costs	(19,540)	1,406	-	(18,134)
Revisions of previous quantity estimates	(45,863)	(7,539)	-	(53,402)
Accretion of discount	118,901	12,224	-	131,125
Net change in income taxes	(20,548)	(77)	-	(20,625)
Purchases of reserves in place	28,884	32,533	-	61,417
Sales of reserves in place	(34,984)	(15)	-	(34,999)
Changes in timing and other	(65,015)	(4,619)	-	(69,634)
December 31, 1992	1,311,416	125,419	-	1,436,835
Sales and transfers of oil and gas produced, net of production costs	(434,609)	(28,802)	287	(463,124)
Net changes in prices and production costs	180,240	28,400	-	208,640
Extensions, discoveries, additions and improved recovery, net of related costs	275,722	27,785	74,191	377,698
Development costs incurred	58,500	13,900	-	72,400
Revisions of estimated development costs	32,196	(1,345)	-	30,851
Revisions of previous quantity estimates	(26,118)	5,668	-	(20,450)
Accretion of discount	145,915	15,348	-	161,263
Net change in income taxes	(71,492)	(9,795)	(24,899)	(106,186)
Purchases of reserves in place	9,462	2,707	-	12,169
Sales of reserves in place	(38,498)	(1,140)	-	(39,638)
Changes in timing and other	(75,043)	(18,374)	-	(93,417)

December 31, 1993	$1,367,691	$159,771	$ 49,579	$1,577,041

</TABLE>

Reserve Quantity Information

Enron's estimates of net proved and proved developed reserves of crude oil, condensate, natural gas liquids and natural gas and of changes in net proved reserves were as follows:

<TABLE>
<CAPTION>

<S>	United States <C>	Foreign(d) <C>	Total <C>
Natural gas (MMcf)			
Proved reserves at			
December 31, 1990(a)	1,343,467	131,508	1,474,975
Revisions of previous estimates	48,371	35	48,406
Purchases in place	45,030	2,885	47,915
Extensions, discoveries and other additions	199,410	6,193	205,603
Sales in place	(6,933)	(2,477)	(9,410)
Production	(173,460)	(9,237)	(182,697)
Proved reserves at			
December 31, 1991(a)	1,455,885	128,907	1,584,792
Revisions of previous estimates	(46,325)	(4,082)	(50,407)
Purchases in place	30,537	112,592	143,129
Extensions, discoveries and other additions	228,044	6,336	234,380
Sales in place	(27,707)	(2)	(27,709)
Production	(200,054)	(11,249)	(211,303)
Proved reserves at			
December 31, 1992(a)	1,440,380(b)	232,502	1,672,882
Revisions of previous estimates	(31,282)	11,058	(20,224)
Purchases in place	9,183	2,627	11,810
Extensions, discoveries and other additions	234,858	148,970	383,828
Sales in place	(12,453)	(1,501)	(13,954)
Production	(240,014)	(22,137)	(262,151)
Proved reserves at			
December 31, 1993(a)	1,400,672(b)	371,519	1,772,191
	United States	Foreign(d)	Total
Liquids (MBbl)(c)			
Proved reserves at			
December 31, 1990(a)	16,272	6,856	23,128
Revisions of previous estimates	(86)	256	170
Purchases in place	173	42	215
Extensions, discoveries and other additions	983	310	1,293
Sales in place	(1,248)	(25)	(1,273)
Production	(2,272)	(927)	(3,199)
Proved reserves at			
December 31, 1991(a)	13,822	6,512	20,334
Revisions of previous estimates	365	(885)	(520)
Purchases in place	65	-	65
Extensions, discoveries and other additions	2,320	698	3,018
Sales in place	(296)	(4)	(300)
Production	(2,411)	(963)	(3,374)
Proved reserves at			
December 31, 1992(a)	13,865(b)	5,358	19,223
Revisions of previous estimates	1,490	(536)	954
Purchases in place	15	489	504
Extensions, discoveries and other additions	3,552	3,366	6,918
Sales in place	(3,230)	(23)	(3,253)
Production	(2,520)	(965)	(3,485)
Proved reserves at			
December 31, 1993(a)	13,172(b)	7,689	20,861
Proved developed reserves			
Natural gas (MMcf)			
December 31, 1990	1,023,711	114,045	1,137,756
December 31, 1991	1,138,530	112,975	1,251,505
December 31, 1992	1,168,386(b)	194,366	1,362,752
December 31, 1993	1,167,313(b)	321,965	1,489,278
Liquids (MBbl)(c)			
December 31, 1990	15,269	6,804	22,073
December 31, 1991	13,002	6,484	19,486
December 31, 1992	12,762(b)	5,329	18,091
December 31, 1993	11,165(b)	7,000	18,165

<FN>

(a) Includes reserves attributable to a 20% minority interest at December 31, 1993 and 1992 and a 16% minority interest at December 31, 1991 and 1990.

(b) Includes approximately 87 billion cubic feet equivalent (96 trillion British thermal units) in 1993 and 114 billion cubic feet equivalent (126 trillion British thermal units) in 1992 associated with a volumetric production payment sold effective October 1, 1992, as amended, to be delivered over a seventy-eight month period which period commenced October 1, 1992 (see Note 8).

(c) Includes crude oil, condensate and natural gas liquids.

(d) Includes Canada and Trinidad.

</TABLE>

Enron Corp. and Subsidiaries

Supplemental Financial Information (unaudited)

Quarterly Results(b)

<TABLE>
<CAPTION>

(In Thousands, Except Per Share Amounts) <S>	Operating Revnues <C>	Gross Profit <C>	Income Before Interest Minority Interest and Income Taxes <C>	Net Income <C>	Primary Earnings Per Share(a) Net Income <C>	Fully Diluted Earnings Per Share(a) Net Income <C>
1993						
First Quarter	$1,857,455	$600,994	$268,249	$146,228	$.60	$.55
Second Quarter	1,907,115	530,388	151,673	61,245	.24	.23
Third Quarter	1,933,666	649,663	168,834	20,995	.07	.07
Fourth Quarter	2,274,246	625,411	208,911	104,054	.42	.39
1992						
First Quarter	$1,519,092	$565,268	$237,249	$115,764	$.54	$.49
Second Quarter	1,335,424	481,332	155,032	50,565	.21	.21
Third Quarter	1,521,794	513,766	150,179	40,887	.15	.15
Fourth Quarter	2,032,963	626,512	224,722	98,969	.40	.37

<FN>

(a) The sum of earnings per share for the four quarters may not equal the total earnings per share for the year due to changes in the average number of common shares outstanding.

(b) Reclassified, see Note 1.

</TABLE>

<TABLE>

Exhibit 11

ENRON CORP. AND SUBSIDIARIES
Calculation of Earnings Per Share
(Unaudited)

<CAPTION>

	Year Ended December 31, 1993	1992	1991
	(in thousands except per share amounts)		
<S>	<C>	<C>	<C>
Primary Earnings Per Share			
Earnings on common stock			
Income before extraordinary items	$332,522	$328,800	$232,146
Preferred stock dividends	(16,919)	(22,109)	(24,740)
	315,603	306,691	207,406
Extraordinary items	-	(22,615)	-
	$315,603	$284,076	$207,406
Average number of common shares outstanding	239,019	219,965	202,080
Primary earnings per share of common stock			
Income before extraordinary items	$ 1.32	$ 1.39	$ 1.03
Extraordinary items	-	(.10)	-
	$ 1.32	$ 1.29	$ 1.03
Fully Diluted Earnings Per Share			
Adjusted earnings on common stock			
Income before extraordinary items	$332,522	$328,800	$232,146
Preferred stock dividends	(16,919)	(22,109)	(24,740)
Add back:			
Dividends on convertible preferred stock	16,919	22,109	24,740
Interest paid on convertible debentures	-	1,463	6,309
	332,522	330,263	238,455
Extraordinary items	-	(22,615)	-
	$332,522	$307,648	$238,455
Average number of common shares outstanding on a fully diluted basis			
Average number of common shares outstanding	239,019	219,965	202,080
Additional shares issuable upon:			
Conversion of preferred stock	22,379	29,248	32,192
Conversion of convertible debentures	-	1,966	7,618
Exercise of stock options reduced by the number of shares which could have been purchased with the proceeds from exercise of such options	3,930	3,064	972

	265,328	254,243	242,862
Fully diluted earnings per share of common stock			
Income before extraordinary items	$ 1.25	$ 1.30	$ .98
Extraordinary items	-	(.09)	-
	$ 1.25	$ 1.21	$ .98

</TABLE>

Exhibit 23

CONSENT OF INDEPENDENT PUBLIC ACCOUNTANTS

As independent public accountants, we hereby consent to the incorporation of our report dated February 18, 1994 included in this Form 8-K, into Enron Corp.'s previously filed Registration Statement Nos. 2-90992 (1984 Stock Option Plan), 2-86917 (Dividend Reinvestment Plan), 33-13397 (Savings Plan), 33-34796 (Savings Plan), 33-52261 (Savings Plan), 33-13498 (1986 Stock Option Plan), 33-35065 (Employee Stock Ownership Plan), 33-43324 ($300 million Debt Securities), 33-50641 (Enron Corp. Debt Securities and Second Preferred Stock and Enron Capital LLC Preferred Shares), 33-27893 (1988 Stock Option Plan), 33-46459 ($700 million Senior Subordinated Debt Securities), 33-55580 (569,354 Shares of Common Stock), 33-54132 (395,935 Shares of Common Stock), 33-52768 (Enron Corp. 1991 Stock Plan), 33-49839 (1,253,768 Shares of Common Stock), and 33-52143 (955,640 Shares of Common Stock). It should be noted that we have not audited any financial statements of Enron Corp. subsequent to December 31, 1993 or performed any audit procedures subsequent to the date of our report.

ARTHUR ANDERSEN & CO.

Houston, Texas
March 1, 1994