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

Form 10-K

(Mark One)

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

For the fiscal year ended December 31, 2000

OR

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

For the transition period from to .

Commission File Number 1-14365

El Paso Corporation

(formerly El Paso Energy Corporation)

(Exact Name of Registrant as Specified in Its Charter)

Delaware	**76-0568816**
(State or Other Jurisdiction of Incorporation or Organization)	(I.R.S. Employer Identification No.)
El Paso Building 1001 Louisiana Street Houston, Texas	**77002**
(Address of Principal Executive Offices)	(Zip Code)

Registrant's Telephone Number, Including Area Code: (713) 420-2131

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

Title of Each Class	Name of Each Exchange on which Registered
Common Stock, par value $3 per share	New York Stock Exchange
Preferred Stock Purchase Rights	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: None

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

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

State the aggregate market value of the voting stock held by non-affiliates of the registrant.

Aggregate market value of the voting stock (which consists solely of shares of common stock) held by non-affiliates of the registrant as of March 16, 2001, computed by reference to the closing sale price of the registrant's common stock on the New York Stock Exchange on such date: $35,108,511,995

Indicate the number of shares outstanding of each of the registrant's classes of common stock, as of the latest practicable date.

Common Stock, par value $3 per share. Shares outstanding on March 16, 2001: 508,892,767

Documents Incorporated by Reference

List hereunder the following documents if incorporated by reference and the part of the Form 10-K (e.g., Part I, Part II, etc.) into which the document is incorporated: Portions of our definitive Proxy Statement for the 2001 Annual Meeting of Stockholders, to be filed not later than 120 days after the end of the fiscal year covered by this report, are incorporated by reference into Part III.

EL PASO CORPORATION

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Below is a list of terms that are common to our industry and used throughout this document:

/d	= per day	Mcf	= thousand cubic feet
Bbl	= barrels	Mcfe	= thousand cubic feet of gas equivalents
BBtu	= billion British thermal units	MMcf	= million cubic feet
BBtue	= billion British thermal unit equivalents	MMcfe	= million cubic feet of gas equivalents
Bcf	= billion cubic feet	Mgal	= thousand gallons
MBbls	= thousand barrels	MWh	= megawatt hours
MMBbls	= million barrels	MMWh	= thousand megawatt hours
MMBtu	= million British thermal units	Tcfe	= trillion cubic feet of gas equivalents

When we refer to natural gas and oil in "equivalents," we are doing so to compare quantities of oil with quantities of natural gas or to express these different commodities in a common unit. In calculating equivalents, we use a generally recognized standard in which one Bbl of oil is equal to six Mcf of natural gas. Also, when we refer to cubic feet measurements, all measurements are at 14.73 pounds per square inch.

PART I

ITEM 1. BUSINESS

General

We are a global energy company originally founded in 1928 in El Paso, Texas. For many years, we served as a regional pipeline company conducting business mainly in the western United States. However, over the past five years, we have grown into a company whose operations span the wholesale energy value chain, from natural gas production and extraction to power generation. Our substantial growth during this period has been accomplished through a series of strategic acquisitions, transactions, and internal growth initiatives, each of which has enhanced and improved our competitive abilities in the U.S. and global energy markets. Significant milestones include:

Year	Transaction	Impact
1995	Acquisition of Eastex Energy Inc.	Signaled our entry into the wholesale energy marketing business.
1996	$4 billion acquisition of the energy businesses of Tenneco Inc.	Expanded our U.S. interstate pipeline system from coast to coast and signaled our entry into the international energy market.
1998	Acquisition of DeepTech International, Inc.	Expanded our U.S. onshore and offshore gathering capacity and capabilities.
1999	$6 billion merger with Sonat Inc.	Expanded our pipeline operations into the southeast portion of the U.S. and signaled our entrance into the exploration and production business through the addition of 1.5 Tcfe of natural gas reserves.
	Creation of $1.1 billion Electron structure	Provided the vehicle through which we have become a significant non-utility generator of power.
2000	Acquisition of PG&E's Texas Midstream operations	Expanded our midstream operations to cover a majority of the metropolitan markets and industrial hubs in the state of Texas.
2001	Completion of our $24 billion merger with The Coastal Corporation	This merger places us as a top tier participant in every aspect of the wholesale energy marketplace.

With each significant merger and acquisition, we have evaluated our processes and organizational structure to achieve cost savings and operating efficiencies. These actions have included restructuring our workforce and consolidating our operations. These activities occurred again following the completion of our merger with Coastal in January 2001. Also during this period, we have completed numerous smaller acquisitions and transactions to enhance and expand the scope of our core operations and activities. The discussion of our operations and segments that follows in this document does not include the activities or operations of The Coastal Corporation.

Operations

Our principal operations include:

- the transportation, gathering, processing, and storage of natural gas;
- the marketing of energy and energy-related commodities and products;
- the generation of power;
- the development and operation of energy infrastructure facilities; and
- the exploration and production of natural gas and oil.

Our Pipelines segment owns or has interests in approximately 38,000 miles of interstate natural gas pipelines in the U.S. Our systems connect the nation's principal natural gas supply regions to the five largest consuming regions in the United States: the Gulf Coast, California, the Northeast, the Midwest, and the Southeast. These operations represent one of the largest, and only, integrated coast-to-coast mainline natural gas transmission systems in the U.S. Our pipeline systems also own or have interests in over 150 Bcf of storage capacity used to provide a variety of services to our customers.

Our Merchant Energy segment is involved in a broad range of activities in the energy marketplace including asset ownership, trading and risk management and financial services. We are one of North America's largest wholesale energy commodity marketers and traders, and buy, sell, and trade natural gas, power, and other energy commodities in the U.S. and internationally. We are also a significant non-utility owner of electric generating capacity with 64 facilities in 16 countries. Most recently, we have announced our expansion into the liquefied natural gas business, capitalizing upon the increasing U.S. and worldwide demand for natural gas. The financial services businesses of Merchant Energy invest in emerging businesses to facilitate growth in the U.S. and Canadian energy markets. As a global energy merchant, we evaluate and measure risks inherent in the markets we serve, and use sophisticated systems and integrated risk management techniques to manage those risks.

Our Field Services segment provides natural gas gathering, products extraction, fractionation, dehydration, purification, compression and intrastate transmission services. These services include gathering of natural gas from more than 11,000 natural gas wells with over 19,000 miles of natural gas gathering and natural gas liquids pipelines, and 20 natural gas processing, treating, and fractionation facilities located in some of the most prolific and active production areas in the U.S., including the San Juan Basin, east and south Texas, Louisiana, and the Gulf of Mexico. We conduct our intrastate transmission operations through interests in five intrastate systems, which serve a majority of the metropolitan areas and industrial load centers in Texas. Our primary vehicle for growth and development of midstream energy assets is El Paso Energy Partners, L.P., a publicly traded master limited partnership of which our subsidiary is the general partner. Through Energy Partners, we provide natural gas and oil gathering and transportation, storage, and other related services, principally in the Gulf of Mexico.

Our Production segment leases approximately 2.7 million net acres in 11 states, including Louisiana, New Mexico, Texas, Oklahoma, and Arkansas, as well as the Gulf of Mexico. We also have exploration and production rights in Turkey. During 2000, our daily equivalent natural gas production was approximately 0.6 Bcf/d, and our reserves at December 31, 2000 were approximately 1.7 Tcfe.

In addition to our energy activities, we have announced a telecommunications strategy that will leverage our knowledge of the commodity and capital markets into the emerging telecommunications market. Our strategy involves:

- accessing fiber deep within metropolitan markets to aggregate supply in major U.S. cities;
- utilizing fiber rings and key points of interconnection of major carriers and service providers to allow for liquidity to develop in major markets; and
- assembling a high capacity thin fiber national long-haul backbone.

We will overlay against this asset base a merchant-based operating support system and valuation models that will allow us to apply the merchant skills developed in our core commodity business to the rapidly changing telecommunications markets.

Segments

Our business unit activities are segregated into four primary business segments: Pipelines, Merchant Energy, Field Services, and Production. These segments are strategic business units that provide a variety of energy products and services. During 2000, we combined our International and Merchant Energy segments to reflect the ongoing globalization of our Merchant Energy strategy and its operating activities. We manage each segment separately and each requires different technology and marketing strategies. Our telecommunication business is combined with our corporate and other activities. For information relating to operating revenues, operating income, EBIT, and identifiable assets by segment, you should see Item 8, Financial Statements and Supplementary Data, Note 15, which is incorporated herein by reference.

Pipelines

Our Pipelines segment provides natural gas transmission services in the U.S. We conduct our activities through five wholly owned and two partially owned interstate systems along with a liquefied natural gas terminalling facility and natural gas storage facilities. Each of these systems is discussed below:

The TGP system. The Tennessee Gas Pipeline system consists of approximately 14,700 miles of pipeline with a design capacity of 5,970 MMcf/d. During 2000, TGP transported natural gas volumes averaging approximately 73 percent of its capacity. This multiple-line system begins in the natural gas-producing regions of Louisiana, including the Gulf of Mexico, and south Texas and extends to the northeast section of the U.S., including the New York City and Boston metropolitan areas. TGP also has an interconnect at the U.S.-Mexico border. Along its system, TGP has approximately 89 Bcf of underground working gas storage capacity.

The EPNG system. The El Paso Natural Gas system consists of approximately 9,800 miles of pipeline with a design capacity of 4,744 MMcf/d. During 2000, EPNG transported natural gas volumes averaging approximately 82 percent of its capacity. The EPNG system delivers natural gas from the San Juan Basin of northern New Mexico and southern Colorado and the Permian Basin and Anadarko Basin to California, which is its single largest market, as well as markets in Nevada, Arizona, New Mexico, Texas, Oklahoma, and northern Mexico.

The SNG system. The Southern Natural Gas system consists of approximately 8,200 miles of pipeline with a design capacity of 2,834 MMcf/d. During 2000, SNG transported volumes averaging approximately 73 percent of its capacity. SNG's interstate pipeline system extends from gas fields in Texas, Louisiana, Mississippi, Alabama and the Gulf of Mexico to markets in Louisiana, Mississippi, Alabama, Florida, Georgia, South Carolina and Tennessee, including the metropolitan areas of Atlanta and Birmingham. SNG is the principal pipeline supplier to the growing southeastern markets of Alabama and Georgia. In August 2000, the South Georgia Natural Gas system was combined with the SNG system as part of SNG's rate case settlement. Along its system, SNG has approximately 60 Bcf of underground working gas storage capacity.

The Midwestern system. The Midwestern system consists of approximately 400 miles of pipeline with a design capacity of 785 MMcf/d. During 2000, Midwestern transported natural gas volumes averaging approximately 33 percent of its capacity. The Midwestern system connects with the TGP system at Portland, Tennessee, and extends to Chicago to serve the Chicago metropolitan area. As a result of our merger with Coastal in January 2001, we will be required to sell the Midwestern system. We expect to complete the sale in the second quarter of 2001.

The MPC system. The Mojave Pipeline Company system consists of approximately 400 miles of pipeline with a design capacity of approximately 400 MMcf/d. During 2000, MPC transported natural gas volumes approximating 100 percent of its capacity. The MPC system connects with the EPNG transmission system at Topock, Arizona and the Kern River Gas Transmission Company system in California and extends to customers in the vicinity of Bakersfield, California.

Florida Gas Transmission system. We own a 50 percent interest in Citrus Corp., a holding company that owns 100 percent of Florida Gas Transmission Company. Florida Gas is the primary pipeline transporter of natural gas in the state of Florida and the sole pipeline transporter to peninsular Florida. The system consists of approximately 4,800 miles of interstate natural gas pipelines with a design capacity of 1,462 MMcf/d. During 2000, Florida Gas transported volumes averaging approximately 92 percent of its capacity. The system extends from south Texas to a point near Miami, Florida.

Portland Natural Gas Transmission. We own an approximate 19 percent interest in the Portland Natural Gas Transmission system. Portland consists of approximately 300 miles of interstate natural gas pipeline with a design capacity of 215 MMcf/d extending from the Canadian border near Pittsburg, New Hampshire to Dracut, Massachusetts. During 2000, Portland transported volumes averaging approximately 51 percent of its capacity.

Southern LNG, Inc. Southern LNG owns a liquefied natural gas receiving terminal, located on Elba Island, near Savannah, Georgia, capable of achieving a peak send out of 540 MMcf/d and a base load send out of 333 MMcf/d. Inactive since the early 1980s, Southern LNG received an order from the Federal Energy Regulatory Commission (FERC) in March 2000 granting it permission to reactivate the receiving terminal. We expect the terminal to be in service in the fourth quarter of 2001.

Bear Creek Storage. Bear Creek Storage Company owns and operates an underground natural gas storage facility located in Louisiana. The facility has a capacity of 50 Bcf of base gas and 58 Bcf of working storage. Bear Creek's working storage capacity is committed equally to the TGP and SNG systems under long-term contracts.

Regulatory Environment

Our interstate natural gas systems and storage operations are regulated by FERC under the Natural Gas Act of 1938 and the Natural Gas Policy Act of 1978. Each system operates under separate FERC approved tariffs that establish rates, terms, and conditions under which each system provides services to its customers. Generally, FERC's authority extends to:

- transportation of natural gas, rates, and charges;
- certification and construction of new facilities;
- extension or abandonment of services and facilities;
- maintenance of accounts and records;
- depreciation and amortization policies;
- acquisition and disposition of facilities;
- initiation and discontinuation of services; and
- various other matters.

Our wholly owned and investee pipelines have tariffs established through filings with FERC that have a variety of terms and conditions, each of which affects its operations and its ability to recover fees for the services it provides. By and large, changes to these fees or terms can only be implemented upon approval by FERC.

Our interstate pipeline systems are also subject to the Natural Gas Pipeline Safety Act of 1968 that establishes pipeline and liquefied natural gas plant safety requirements, the National Environmental Policy Act, and other environmental legislation. Each of our systems has a continuing program of inspection designed to keep all of our facilities in compliance with pollution control and pipeline safety requirements. We believe that our systems are in substantial compliance with the applicable requirements.

For a further discussion of significant rate and regulatory matters, see Item 8, Financial Statements and Supplementary Data, Note 11.

Markets and Competition

Our interstate systems face varying degrees of competition from alternative energy sources, such as electricity, hydroelectric power, coal, and fuel oil. Also, the potential consequences of proposed and ongoing restructuring and deregulation of the electric power industry are currently unclear. Restructuring and deregulation may benefit the natural gas industry by creating more demand for natural gas turbine generated electric power, or it may hamper demand by allowing a more effective use of surplus electric capacity through increased wheeling as a result of open access.

TGP. TGP's customers include natural gas producers, marketers and end-users, as well as other gas transmission and distribution companies, none of which individually represents more than 10 percent of the revenues on TGP's system. Currently, over 70 percent of TGP's capacity is subject to firm contracts expiring after 2001. These contracts have an average term in excess of five years. TGP continues to pursue future markets and customers for the capacity that is not committed beyond 2001 and expects this capacity will be placed under a combination of long-term and short-term contracts. However, there can be no assurance that TGP will be able to replace these contracts or that the terms of new contracts will be as favorable to TGP as the existing ones.

In a number of key markets, TGP faces competitive pressures from other major pipeline systems, which enable local distribution companies and end-users to choose a supplier or switch suppliers based on the short-term price of natural gas and the cost of transportation. Competition among pipelines is particularly intense in TGP's supply areas, Louisiana and Texas. In some instances, TGP has had to discount its transportation rates in order to maintain market share. The renegotiation of TGP's expiring contracts may be adversely affected by these competitive factors.

EPNG. EPNG faces competition from other pipeline companies that transport natural gas to the California market. EPNG's current capacity to deliver natural gas to California is approximately 3.3 Bcf/d, and the combined capacity of all pipeline companies serving the California market is approximately 6.9 Bcf/d. In 2000, the demand for interstate pipeline capacity to California averaged 5.4 Bcf/d, equivalent to approximately 78 percent of the total interstate pipeline capacity serving that state. Natural gas shipped to California across the EPNG system represented approximately 35 percent of the natural gas consumed in the state in 2000. EPNG's ability to remarket its capacity under expiring contracts may be adversely affected by excess capacity into California.

The significant customers served by EPNG in California during 2000 included Southern California Gas Company, with capacity of 1,150 MMcf/d under contract until August 2006, and Merchant Energy, with capacity of 1,221 MMcf/d under contract through May 2001. In February 2001, EPNG completed its open season on the capacity held by Merchant Energy and all of the available capacity was re-subscribed. Contracts were awarded to 30 different entities, including 271 MMcf/d to Merchant Energy, all at published tariff rates under contracts with durations from 17 months to 15 years.

SNG. SNG's customers include distribution and industrial customers, electric generation companies, gas producers, other gas pipelines and gas marketing and trading companies. SNG provides transportation services in both its natural gas supply and market areas. SNG's contracts to provide firm transportation service for its customers are for varying amounts and periods of time. Substantially all of the firm transportation capacity currently available in SNG's two largest market areas is fully subscribed. The significant customers served by SNG include:

- Atlanta Gas Light Company, with capacity of 770 MMcf/d under contracts that expire beginning in 2005 through 2007, with the majority expiring in 2005;
- Alabama Gas Corporation, with capacity of 384 MMcf/d under contracts that expire beginning in 2005 through 2008, with the majority expiring in 2008; and
- South Carolina Pipeline Corporation, with capacity of 188 MMcf/d under contract which expires primarily in 2005.

Nearly all of SNG's firm transportation contracts automatically extend the term for additional months or years unless notice of termination is given by one of the parties.

Competition among pipelines is strong in a number of SNG's key markets. Customers purchase natural gas supply from producers and natural gas marketing companies in unregulated transactions and contract with SNG for transportation services to deliver this supply to their markets. SNG's three largest customers are able to obtain a significant portion of their natural gas requirements through transportation from other pipelines. In addition, SNG competes with several pipelines for the transportation business of many of its other customers. The competition with such pipelines is intense, and SNG must, at times, discount its transportation rates in order to maintain market share.

Merchant Energy

Our Merchant Energy segment is a market maker involved in a broad range of activities in the wholesale energy marketplace, including asset ownership, trading and risk management, and financial services. Merchant Energy is organized into six functional units, each with complementary activities that support our overall global merchant energy model. These units are:

- Marketing and Origination;
- Trading and Risk Management;
- Power Generation;
- LNG;
- Financial Services; and
- Operations.

Marketing and Origination. The Marketing and Origination unit provides energy solutions in natural gas, power, and other energy commodity markets. This unit also markets capacity from power and natural gas assets, and creates innovative structured transactions to enhance the value of Merchant Energy's assets. This unit is able to provide its customers with flexible solutions to meet their energy supply and financial risk management requirements by utilizing its knowledge of the marketplace, natural gas pipelines, storage, and power transmission infrastructures, supply aggregation, transportation management and valuation, and integrated price risk management. They also enter into short and long term energy supply and purchase contracts and perform total energy infrastructure outsourcing for customers.

Trading and Risk Management. The Trading and Risk Management unit trades natural gas, power, other energy commodities, and related financial instruments in North America and Europe and provides pricing and valuation analysis for the Marketing and Origination unit. Using the financial markets, this unit manages the inherent risk of Merchant Energy's asset and trading portfolios using value-at-risk limits set by our Board of Directors and optimizes the value inherent in the segment's asset portfolio.

During 2000, the Marketing and Origination and Trading and Risk Management units grew their combined physical and financially settled volumes by approximately 40% to 106,656 BBtue/d. Power marketed during 2000 increased by over 43 percent. We expect our marketed volumes to significantly increase in 2001.

Marketing and trading energy commodity volumes for the years ended December 31 were:

	2000	1999	1998
Physical natural gas marketed (Bbtu/d)	6,899	6,713	7,089
Power marketed (MMWh)	113,652	79,361	55,210
Financial settled volumes (Bbtue/d)	98,574	68,678	31,793

Power Generation. Our Power Generation unit is one of the largest non-utility generators in the U.S., and currently owns or has interests in 64 power plants in 16 countries. These plants represent 17,153 gross megawatts of generating capacity. Of these facilities, 75 percent are natural gas fired, 15 percent are geothermal, with the remaining 10 percent utilizing natural gas liquids, coal, and other fuels. During 2000, Merchant Energy continued acquiring domestic non-utility generation (NUG) assets, especially those with above-market power purchase agreements. As part of these efforts, we used Chaparral Investors, L.L.C. (also referred to as Electron) to expand Merchant Energy's growth in the power generation business. Through Chaparral, Merchant Energy has invested in 27 U.S. power generation facilities with a total generating capacity of approximately 5,600 gross megawatts. A subsidiary of Merchant Energy serves as the manager of Chaparral and its wholly-owned subsidiary, Mesquite Investors, L.L.C., under a management agreement, which expires in 2006. As compensation for managing Chaparral, Merchant Energy is paid an annual performance-based management fee.

Detailed below are brief descriptions, by region, of Merchant Energy's power generation projects that are either operational or in various stages of construction or development.

Region	Project Status	Number of Facilities	Gross Megawatts
North America			
East Coast	Operational	13	3,263
	Under Construction	1	716
	Under Development	3	1,664
Central	Operational	7	1,253
West Coast	Operational	21	1,036
South America	Operational	7	4,114
	Under Construction	1	470
Asia	Operational	5	2,589
	Under Construction	2	1,108
Europe	Operational	3	544
	Under Construction	1	396
Total		64	17,153

LNG. The LNG unit contracts for LNG terminalling and regasification capacity, coordinates short and long term LNG supply deliveries, and is developing an international LNG supply and marketing business. As of December 31, 2000, our LNG unit has contracted for over 280 Bcf per year of LNG regasification capacity at three locations along the Eastern Coast of the U.S. and one location in Louisiana. In the Caribbean, we have contracted for 105 Bcf per year of long term supplies of LNG with deliveries scheduled to begin in 2002.

Financial Services. The Financial Services unit provides financing to the energy and power industries and provides institutional funds management. Merchant Energy owns EnCap, an institutional funds management firm specializing in financing independent oil and natural gas producers. EnCap manages three separate institutional oil and natural gas investment funds in the U.S., and serves as investment advisor to Energy Capital Investment Company PLC, a publicly traded investment company in the United Kingdom. During 2000, we acquired Enerplus Global Energy Management, Inc., an institutional and retail funds management firm in Canada. Combined, EnCap and Enerplus manage funds with a market value of approximately $2 billion. In addition to EnCap and Enerplus, Merchant Energy's Financial Services unit holds investments of approximately $62 million. Also in 2000, it began originating financing for North American power development projects. As of December 31, 2000, it had funded $5 million of loans with additional commitments for $68 million.

Operations. The Operations unit conducts the day-to-day operations of Merchant Energy's assets in close coordination with the Marketing and Origination, and Trading and Risk Management units. Our Operations unit operates 13 generating facilities in the U.S. and three facilities in two foreign countries.

Finance and Administration. In addition to its functional units, Merchant Energy has a Finance and Administration unit that implements financing strategies for its assets, and provides accounting and administrative services for the segment's activities.

Regulatory Environment

Merchant Energy's domestic power generation activities are regulated by FERC under the Federal Power Act with respect to its rates, terms, and conditions of service and other reporting requirements. In addition, exports of electricity outside of the U.S. must be approved by the Department of Energy. Its cogeneration power production activities are regulated by FERC under the Public Utility Regulatory Policies Act with respect to rates, procurement and provision of services, and operating standards. All of its power generation activities are also subject to U.S. Environmental Protection Agency (EPA) regulations.

Merchant Energy's foreign operations are regulated by numerous governmental agencies in the countries in which these projects are located. Generally, many of the countries in which Merchant Energy conducts and will conduct business have recently developed or are developing new regulatory and legal structures to accommodate private and foreign-owned businesses. These regulatory and legal structures and their interpretation and application by administrative agencies are relatively new and sometimes limited. Many detailed rules and procedures are yet to be issued and we expect that the interpretation of existing rules in these jurisdictions will evolve over time. We believe that our operations are in compliance in all material respects with all applicable environmental laws and regulations in the applicable foreign jurisdictions. We also believe that the operations of our projects in many of these countries eventually may be required to meet standards that are comparable in many respects to those in effect in the U.S. and in countries within the European Community.

Markets and Competition

Merchant Energy maintains a diverse supplier and customer base. During 2000, Merchant Energy's activities served over 900 suppliers and over 1,300 sales customers around the world.

Merchant Energy's trading, marketing, and power development businesses operate in a highly competitive environment. Its primary competitors include:

- affiliates of major oil and natural gas producers;
- multi-national energy infrastructure companies;
- large domestic and foreign utility companies;
- affiliates of large local distribution companies;
- affiliates of other interstate and intrastate pipelines; and
- independent energy marketers and power producers with varying scopes of operations and financial resources.

Merchant Energy competes on the basis of price, access to production, understanding of pipeline and transmission networks, imbalance management, experience in the marketplace, and counterparty credit.

Many of Merchant Energy's generation facilities sell power pursuant to long-term agreements with investor-owned utilities in the U.S. Because of the terms of its power purchase agreements for its facilities, Merchant Energy's revenues are not significantly impacted by competition from other sources of generation for these facilities. The power generation industry is rapidly evolving, and regulatory initiatives have been adopted at the federal and state level aimed at increasing competition in the power generation business. As a result, it is likely that when the power purchase agreements expire, these facilities will be required to compete in a significantly different market in which operating efficiency and other economic factors will determine success. Merchant Energy is likely to face intense competition from generation companies as well as from the wholesale power markets. The successful acquisition of new business opportunities is dependent upon Merchant Energy's ability to respond to requests to provide new services, mitigate potential risks, and maintain strong business development, legal, financial, and operational support teams with experience in the respective marketplace.

Field Services

Our Field Services segment provides customers with wellhead-to-mainline services, including natural gas gathering, storage, products extraction, fractionation, dehydration, purification, compression, transportation of natural gas and natural gas liquids, and intrastate natural gas transmission services. It also provides well-ties and offers real-time information services, including electronic wellhead gas flow measurement, and works with Merchant Energy to provide fully bundled natural gas services with a broad range of pricing options as well as financial risk management products.

Field Services' assets include natural gas gathering and natural gas liquids pipelines, treating, processing, and fractionation facilities in the San Juan Basin, the producing regions of east and south Texas, and Louisiana.

Through our subsidiaries, we own a one percent general partner interest in Energy Partners and a one percent non-managing interest in many of its subsidiaries. We also own 27.8 percent of the partnership's common units and $170 million of its preferred units. Energy Partners is our primary vehicle for the acquisition and development of midstream energy infrastructure assets. Energy Partners' assets provide gathering, transportation, storage, and other related activities for producers of natural gas and oil. Energy Partners owns or has interests in twelve natural gas and oil pipeline systems, seven offshore platforms, two natural gas storage facilities, five producing oil and natural gas properties, and an overriding royalty interest in a non-producing oil and natural gas property. As a result of our merger with Coastal in January 2001, Energy Partners sold its interests in several assets in the Gulf of Mexico. These sales consisted of interests in seven natural gas pipeline systems, a dehydration facility and two offshore platforms. Energy Partners completed these sales in March of 2001.

In December 2000, Field Services purchased PG&E's Texas Midstream operations. The acquired assets consisted of 7,500 miles of natural gas transmission and natural gas liquids pipelines that transport approximately 2.8 Bcf/d, nine natural gas processing and fractionation plants that process 1.5 Bcf/d, and rights to 7.2 Bcf of natural gas storage capacity. These assets serve a majority of the metropolitan areas and the largest industrial load centers in Texas, as well as numerous natural gas trading hubs. These assets also create a physical link between our EPNG and TGP systems. In the first quarter of 2001, Field Services sold some of these acquired natural gas liquids transportation and fractionation assets to Energy Partners. The assets sold included more than 600 miles of natural gas liquids gathering and transportation pipelines and three fractionation plants located in south Texas.

The following tables provide information concerning Field Services' natural gas gathering and transportation facilities, its processing facilities, and its facilities accounted for under the equity method as of and for each of the three years ended December 31:

Gathering & Treating	Miles of Pipeline[1]	Throughput Capacity (MMcfe/d)[2]	Average Throughput (BBtue/d)[2] 2000	1999	1998	Percent of Ownership Interest
Western Division	5,555	1,200	1,237	1,262	1,191	100
Eastern Division	1,251	909	271	386	424	100
Central Division[3]	9,890	6,760	1,425	1,528	1,771	100
Energy Partners[4][5]	2,076	1,545	774	698	695	30
Oasis[6]	608	350	268	263	289	—
Viosca Knoll[5]	125	10	6	142	287	—

Processing Plants	Inlet Capacity[2] (MMcf/d)	Avg. Inlet Volume (BBtu/d)[2] 2000	1999	1998	Average Natural Gas Liquids Sales (Mgal/d) 2000	1999	1998	Percent of Ownership Interest
Western Division	600	635	650	586	384	432	370	100
Eastern Division	369	121	140	160	222	264	349	100
Central Division[3]	1,883	309	242	269	307	202	208	100
Coyote Gulch	120	87	97	69	—	—	—	50

(1) Mileage amounts are approximate for the total systems and have not been reduced to reflect Field Services' net ownership.

(2) All volumetric information reflects Field Services' net interest and is subject to increases or decreases depending on operating pressures and point of delivery into or out of the system.

(3) Reflects the acquisition of PG&E's Texas Midstream operations in December 2000.

(4) In the first quarter of 2001, Energy Partners sold their interests in several of its gathering, transmission, and treating systems in the Gulf of Mexico. Total miles of the pipelines sold were 881. Our net interest in these systems included combined throughput capacity of 542 MMcfe/d and average throughput for the years ended December 31, 2000, 1999, and 1998 of 241 BBtue/d, 277 BBtue/d, and 330 BBtue/d.

(5) Field Services sold its 49 percent interest in Viosca Knoll to Energy Partners in June 1999 and its remaining one percent interest in September 2000.

(6) Field Services sold its 35 percent interest in Oasis in December 2000.

Regulatory Environment

Some of Field Services' and Energy Partners' operations are subject to regulation by FERC in accordance with the Natural Gas Act of 1938 and the Natural Gas Policy Act of 1978. Each pipeline subject to regulation operates under separate FERC approved tariffs with established rates, terms and conditions under which the pipeline provides services.

In addition, some of Field Services' and Energy Partners' operations, directly owned or owned through equity investments, are subject to the Natural Gas Pipeline Safety Act of 1968, the Hazardous Liquid Pipeline Safety Act, and the National Environmental Policy Act. Each of the pipelines has a continuing program of inspection designed to keep all of the facilities in compliance with pollution control and pipeline safety requirements and Field Services and Energy Partners believe that these systems are in substantial compliance with applicable requirements.

Markets and Competition

Field Services competes with, among others, major interstate and intrastate pipeline companies in the transportation of natural gas and natural gas liquids. Field Services also competes with major integrated energy companies, independent natural gas gathering and processing companies, natural gas marketers, and oil and natural gas producers in gathering and processing natural gas and natural gas liquids. Competition for throughput and natural gas supplies is based on a number of factors, including price, efficiency of facilities, gathering system line pressures, availability of facilities near drilling activity, service, and access to favorable downstream markets.

Production

Our Production segment is engaged in the exploration for and the acquisition, development, and production of natural gas, oil, and natural gas liquids in the major producing basins of the United States. Production has onshore and coal seam operations and properties in 11 states and offshore operations and properties in federal and state waters in the Gulf of Mexico. It also has exploration and production rights in Turkey.

Production sells its natural gas primarily at spot-market prices. It sells its natural gas liquids at market prices under monthly or long-term contracts and its oil production at posted prices, subject to adjustments for gravity and transportation. Production engages in hedging activities on its natural gas and oil production in order to stabilize cash flows and reduce the risk of downward commodity price movements on sales of its production. A significant portion of the segment's 2000 production was hedged by entering into third-party contracts and forward sales.

Strategically, Production emphasizes disciplined investment criteria and manages its existing production portfolio to maximize volumes and minimize costs. Production expects to continue an active onshore and offshore drilling program to capitalize on its land and seismic holdings. Production is also pursuing strategic acquisitions of producing properties and the development of coal seam projects. In 2000, Production replaced 229 percent of the reserves it produced.

Natural Gas and Oil Reserves

The following table details Production's proved reserves at December 31, 2000. Information in the table is based upon the reserve report prepared by Production dated January 1, 2001, and agrees with Production's estimate of reserves filed with other federal agencies except for differences of less than 5 percent resulting from actual production, acquisitions, property sales, and necessary reserve revisions and additions to reflect actual experience.

	Net Proved Reserves(1)		
	Natural Gas (MMcf)	Liquids(2) (MBbls)	Total (MMcfe)
Producing	912,567	13,672	994,598
Non-Producing	148,887	4,969	178,698
Undeveloped	490,882	11,854	562,008
Total proved reserves	1,552,336	30,495	1,735,304

(1) Net proved reserves exclude royalties and interests owned by others and reflects contractual arrangements and royalty obligations in effect at the time of the estimate.

(2) Includes oil, condensate, and natural gas liquids.

There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting future rates of production and timing of development expenditures, including many factors beyond the control of Production. The reserve data represents only estimates. Reservoir engineering is a subjective process of estimating underground accumulations of natural gas and oil that cannot be measured in an exact manner. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretations and judgment. As a result, estimates of different engineers often vary. In addition, results of drilling, testing, and production subsequent to the date of an estimate may justify revision of such estimate. Reserve estimates are often different from the quantities of natural gas and oil that are ultimately recovered. The meaningfulness of reserve estimates is highly dependent upon the accuracy of the assumptions upon which they were based. In general, the volume of production from natural gas and oil properties owned by Production declines as reserves are depleted. Except to the extent Production conducts successful exploration and development activities or acquires additional properties containing proved reserves, or both, the proved reserves of Production will decline as reserves are produced.

For further discussion of our reserves, see Item 8, Financial Statements and Supplementary Data, Note 19.

Wells and Acreage

The following table details Production's gross and net interest in developed and undeveloped onshore, offshore, and coal seam acreage at December 31, 2000. Any acreage in which Production's interest is limited to owned royalty, overriding royalty, and other similar interests is excluded.

	Developed		Undeveloped		Total	
	Gross	Net	Gross	Net	Gross	Net
Onshore	488,988	297,334	946,288	668,537	1,435,276	965,871
Offshore	292,660	196,525	1,087,567	1,040,145	1,380,227	1,236,670
Coal seam	32,634	26,666	581,045	437,493	613,679	464,159
Total	814,282	520,525	2,614,900	2,146,175	3,429,182	2,666,700

The domestic net developed acreage is concentrated primarily in the Gulf of Mexico (38 percent), Texas (21 percent), Oklahoma (18 percent), and Louisiana (18 percent). Approximately 19 percent, 18 percent, and 5 percent of our total domestic net undeveloped acreage is under leases that have minimum remaining primary terms expiring in 2001, 2002, and 2003.

The following table details Production's working interests in onshore, offshore, and coal seam natural gas and oil wells at December 31, 2000. Gross wells include 21 multiple completions.

	Productive Natural Gas Wells		Productive Oil Wells		Total Productive Wells		Number of Wells Being Drilled	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Onshore	1,393	967	27	25	1,420	992	20	12
Offshore	144	60	15	12	159	72	1	1
Coal seam	1,042	652	—	—	1,042	652	57	41
Total	2,579	1,679	42	37	2,621	1,716	78	54

The following table details Production's exploratory and development wells drilled during the years 1998 through 2000.

	Net Exploratory Wells Drilled			Net Development Wells Drilled		
	2000	1999	1998	2000	1999	1998
Productive	5	12	15	199	116	204
Dry	11	14	19	5	2	18
Total	16	26	34	204	118	222

The information above should not be considered indicative of future drilling performance, nor should it be assumed that there is any correlation between the number of productive wells drilled and the amount of natural gas and oil that may ultimately be recovered.

Net Production, Unit Prices, and Production Costs

The following table details Production's net production volumes, average sales prices received, and average production costs associated with the sale of natural gas and oil for each of the years ended December 31:

	2000	1999	1998
Net Production:			
Natural Gas (Bcf)	188	186	226
Oil, Condensate, and Liquids (MMBbls)	5	6	8
Total (Bcfe)	219	221	276
Average Realized Sales Price:			
Natural Gas ($/Mcf)	$ 2.26	$ 2.05	$ 1.95
Oil, Condensate, and Liquids ($/Bbl)	$17.98	$15.46	$12.22
Average Production Cost ($/Mcfe)(1)	$ 0.34	$ 0.44	$ 0.33

(1) Includes direct lifting costs (labor, repairs and maintenance, materials, and supplies) and the administrative costs of production offices, insurance, and property and severance taxes.

Acquisition, Development, and Exploration Expenditures

The following table details information regarding Production's costs incurred in its development, exploration, and acquisition activities during each of the years ended December 31:

	2000	1999	1998
		(In millions)	
Acquisition Costs:			
Proved	$ 74	$ 3	$ 2
Unproved	41	45	48
Development Costs	269	178	375
Exploration Costs:			
Delay Rentals	6	7	11
Seismic Acquisition and Reprocessing	13	58	53
Drilling	81	74	92
Total Capital Expenditures	$484	$365	$581

Regulatory and Operating Environment

The federal government and the states in which Production operates or owns interests in producing properties regulate various matters affecting natural gas and oil production, including drilling and spacing of wells, conservation, forced pooling, and protection of correlative rights among interest owners. Production is also subject to governmental safety regulations in the jurisdictions in which it operates.

Production's operations under federal natural gas and oil leases are regulated by the statutes and regulations of the United States Department of the Interior that currently impose liability upon lessees for the cost of pollution resulting from their operations. Royalty obligations on all federal leases are regulated by the Minerals Management Service, which has promulgated valuation guidelines for the payment of royalties by producers. Other federal, state, and local laws and regulations relating to the protection of the environment affect Production's natural gas and oil operations through their effect on the construction and operation of facilities, drilling operations, production, or the delay or prevention of future offshore lease sales. We maintain substantial insurance on behalf of Production for sudden and accidental spills and oil pollution liability.

Production's business has operating risks normally associated with the exploration for and production of natural gas and oil, including blowouts, cratering, pollution, and fires, each of which could result in damage to life or property. Offshore operations may encounter usual marine perils, including hurricanes and other adverse weather conditions, and governmental regulations as well as interruption or termination by governmental authorities based on environmental and other considerations. Customary with industry practices, we maintain broad insurance coverage on behalf of Production with respect to potential losses resulting from these operating hazards.

Markets and Competition

The natural gas and oil business is highly competitive in the search for and acquisition of additional reserves and in the sale of natural gas, oil, and liquids. Production's competitors include major and intermediate sized oil and natural gas companies, independent oil and natural gas operations, and individual producers or operators with varying scopes of operations and financial resources. Competitive factors include price, contract terms, and quality of service. To some degree, price competition is mitigated by Production's hedging activities.

Corporate and Other Operations

Through our corporate group, we perform management, legal, financial, tax, consulting, administrative and other services for our operating business segments. The costs of providing these services are allocated to our business segments. Our other operations include the assets and operations of our telecommunications business.

Environmental

A description of our environmental activities is included in Item 8, Financial Statements and Supplementary Data, Note 11, and is incorporated by reference herein.

Employees

As of March 19, 2001, including the employees we acquired as a result of our merger with Coastal, we had approximately 15,000 full-time employees, of which 600 are subject to collective bargaining arrangements.

Executive Officers of the Registrant

Our executive officers as of March 19, 2001, are listed below. Prior to August 1, 1998, all references to El Paso refer to positions held with El Paso Natural Gas Company.

Name	Office	Officer Since	Age
William A. Wise	Chairman, President, and Chief Executive Officer of El Paso	1983	55
H. Brent Austin	Executive Vice President and Chief Financial Officer of El Paso	1992	46
Ralph Eads	Executive Vice President of El Paso and President of El Paso's Merchant Energy Group	1999	41
Joel Richards III	Executive Vice President of El Paso	1990	54
John W. Somerhalder II	Executive Vice President of El Paso and President of El Paso's Pipeline Group	1990	45
Britton White Jr.	Executive Vice President and General Counsel of El Paso	1991	57
Rodney D. Erskine	President of El Paso Production	2001	56
John D. Hushon	President of El Paso Merchant Energy Europe	1996	55
Greg G. Jenkins	President of El Paso Global Networks	1996	43
Byron R. Kelley	President of El Paso Energy International	2001	53
Robert G. Phillips	President of El Paso Field Services	1995	46
Clark C. Smith	President of El Paso Merchant Energy North America	2000	46
William A. Smith	President of El Paso Global LNG	1999	56
Tom M. Wade	President of Petroleum Markets	2001	48

Mr. Wise has been Chief Executive Officer since January 1990 and the Chairman of the Board of Directors since January 2001. He was also Chairman of the Board from January 1994 until October 1999. Mr. Wise became the President of El Paso in July 1998 and also served in that capacity from January 1990 to April 1996. Mr. Wise is a member of the Board of Directors of Battle Mountain Gold Company and is the Chairman of the Board of El Paso Tennessee Pipeline Co. and El Paso Energy Partners Company, the general partner of Energy Partners.

Mr. Austin has been an Executive Vice President since May 1995. He has been our Chief Financial Officer since April 1992. Prior to that period, he served in various positions with Burlington Resources Inc.

Mr. Eads has been an Executive Vice President since July 1999 and President of the El Paso Merchant Energy Group since January 2001. Mr. Eads was a Managing Director and Co-Head of the Energy Group at Donaldson, Lufkin & Jenrette from January 1996 through June 1999. Prior to that period, he was Managing Director, Head of Energy at S.G. Warburg Company.

Mr. Richards has been an Executive Vice President since December 1996. From January 1991 until December 1996, he was a Senior Vice President of El Paso.

Mr. Somerhalder has been an Executive Vice President of El Paso since April 2000, and President of our Pipeline segment since January 2001. He has been Chairman of the Board of TGP, EPNG, and SNG since January 2000. He was President of TGP from December 1996 to January 2000, President of El Paso Energy Resources Company from April 1996 to December 1996 and a Senior Vice President of El Paso from August 1992 to April 1996.

Mr. White has been an Executive Vice President of El Paso and General Counsel since December 1996. Prior to that period, he was a Senior Vice President and General Counsel of El Paso.

Mr. Erskine has been President of El Paso Production since our merger with Coastal in January 2001. He was Senior Vice President of Coastal from August 1997. He has held various positions with Coastal Oil & Gas Corporation, a subsidiary of Coastal, since 1994.

Mr. Hushon has been President of El Paso Merchant Energy Europe since January 2001. He was President of El Paso International from April 1996 to January 2001. He was Senior Vice President of El Paso International from September 1995 to April 1996. Prior to that period, Mr. Hushon was a senior partner in the law firm of Arent Fox Kintner Plotkin & Kahn.

Mr. Jenkins has been President of El Paso Global Networks since August 2000. He was President of Merchant Energy from December 1996 to August 2000. He was Senior Vice President and General Manager of Entergy Corp. from May 1996 to December 1996. Prior to that period, he was President and Chief Executive Officer of Hadson Gas Services Company.

Mr. Kelley has been President of El Paso International since January 2001. He was Executive Vice President of Business Development and commercial management for El Paso International since 1996. Prior to that period, Mr. Kelley held various positions with Tenneco Energy.

Mr. Phillips has been President of El Paso Field Services since June 1997. He was President of El Paso Energy Resources Company from December 1996 to June 1997, President of Field Services from April 1996 to December 1996 and was a Senior Vice President of El Paso from September 1995 to April 1996. Prior to that period, Mr. Phillips was Chief Executive Officer of Eastex Energy, Inc.

Mr. Clark C. Smith has been President of El Paso Merchant Energy North America since August 2000. He served as President and CEO of Engage Energy Inc. since 1997. Prior to that period, he held the position of President and CEO of Coastal Gas Marketing Company and held several positions with Enron Corp.

Mr. William A. Smith has been President of El Paso Global LNG since March 2001. He was an Executive Vice President of El Paso from October 1999 to March 2001. He was Executive Vice President and General Counsel of Sonat Inc. from 1995 to September 1999. He was Vice Chairman of Sonat Exploration from 1994 to 1995 and Chairman and President of SNG from 1989 to 1994.

Mr. Wade has been President of Petroleum Markets since January 2001. He has held various positions with Coastal since 1980.

Executive officers hold offices until their successors are elected and qualified, subject to their earlier removal.

ITEM 2. PROPERTIES

A description of our properties is included in Item 1, Business, and is incorporated by reference herein.

We are of the opinion that we have satisfactory title to the properties owned and used in our businesses, subject to liens for current taxes, liens incident to minor encumbrances, and easements and restrictions that do not materially detract from the value of such property or the interests therein or the use of such properties in our businesses. We believe that our physical properties are adequate and suitable for the conduct of our business in the future.

ITEM 3. LEGAL PROCEEDINGS

See Item 8, Financial Statements and Supplementary Data, Note 11, which is incorporated herein by reference.

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

None.

PART II

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

Our common stock is traded on the New York Stock Exchange under the symbol EPG. As of March 16, 2001, we had 68,070 stockholders of record. This does not include individual participants who own our common stock, but whose shares are held by a clearing agency, such as a broker or bank.

The following table reflects the quarterly high and low sales prices for our common stock based on the daily composite listing of stock transactions for the New York Stock Exchange and the cash dividends we declared in each quarter.

	High	Low (Per share)	Dividends
2000			
First Quarter	$42.3125	$30.3125	$0.2060
Second Quarter	52.5000	39.3750	0.2060
Third Quarter	67.5000	46.2500	0.2060
Fourth Quarter	74.2500	57.1300	0.2060
1999			
First Quarter	$39.3750	$30.6875	$0.2000
Second Quarter	38.3750	31.9375	0.2000
Third Quarter	40.5000	34.4375	0.2000
Fourth Quarter	43.4375	33.3750	0.2000

In January 2001, our Board of Directors declared a quarterly dividend of $0.2125 per share of common stock, payable on April 2, 2001, to stockholders of record on March 2, 2001. Future dividends will be dependent upon business conditions, earnings, our cash requirements, and other relevant factors.

In June 1999, our stockholders approved an increase in our authorized common stock to 750 million shares. We also rescinded our common stock repurchase program which authorized us to repurchase up to 10 million shares in order to meet a requirement to treat our 1999 merger with Sonat as a pooling of interests under generally accepted accounting principles.

We have an odd-lot stock sales program available to stockholders who own fewer than 100 shares of our common stock. The voluntary program offers these stockholders a convenient method to sell all of their odd-lot shares at one time without incurring any brokerage costs. We also have a dividend reinvestment and common stock purchase plan available to all of our common stockholders of record. The voluntary plan provides our stockholders a convenient and economical means of increasing their holdings in our common stock. Neither the odd-lot program nor the dividend reinvestment and common stock purchase plan have a termination date, however we may suspend either at any time. You should direct your inquiries to Fleet National Bank, our exchange agent.

ITEM 6. SELECTED FINANCIAL DATA

	Year Ended December 31,				
	2000	1999	1998	1997	1996
	(In millions, except per common share amounts)				
Operating Results Data:[1]					
Operating revenues[2][3]	$21,950	$10,709	$9,560	$10,184	$6,597
Merger-related and asset impairment charges	91	557	15	50	99
Ceiling test charges[4]	—	352	1,035	—	—
Income (loss) before extraordinary items and cumulative effect of accounting change	582	(242)	(306)	405	294
Basic earnings (loss) per common share before extraordinary items and cumulative effect of accounting change	2.53	(1.06)	(1.35)	1.81	1.61
Diluted earnings (loss) per common share before extraordinary items and cumulative effect of accounting change	2.44	(1.06)	(1.35)	1.77	1.59
Cash dividends declared per common share	0.82	0.80	0.76	0.73	0.70
Basic average common shares outstanding	230	228	226	224	183
Diluted average common shares outstanding	243	228	226	229	185

	As of December 31,				
	2000	1999	1998	1997	1996
	(In millions)				
Financial Position Data:[1]					
Total assets[3]	$27,445	$16,667	$14,455	$14,784	$13,206
Long-term debt, less current maturities	5,606	5,223	3,692	3,404	3,251
Company-obligated preferred securities of consolidated trusts	625	325	325	—	—
Minority interest	2,331	1,368	374	380	347
Stockholders' equity	3,569	2,947	3,437	3,921	3,514

(1) Our operating results and financial position reflect the acquisition in June 1996 of Cornerstone Natural Gas, in December 1996 of El Paso Tennessee Pipeline (formerly Tenneco Inc.), in August 1998 of DeepTech International, and in December 2000 of PG&E's Texas Midstream operations. These acquisitions were accounted for as purchases and therefore operating results are included in our results prospectively from the purchase date.

(2) We restated historical operating revenues due to the implementation in 2000 of Emerging Issues Task Force Issue No. 99-19, *Reporting Revenue Gross as a Principal versus Net as an Agent,* which provides guidance on the gross versus net presentation of revenues and expenses. These reclassifications impacted operating revenues and expenses, but had no impact on net income (loss) or earnings per share.

(3) The increase to our 2000 operating revenues and total assets reflects the significant growth in our Merchant Energy operations.

(4) Ceiling test charges are reductions in earnings that result when capitalized costs of natural gas and oil properties exceed the upper limit, or ceiling, on the value of these properties.

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

General

Over the past several years, our business activities and operations have changed dramatically as a result of significant acquisitions, transactions, and internal growth initiatives, designed to enhance our ability to compete effectively in the global energy industry. These changes have significantly expanded our operating scope, our ability to generate operating cash flows and our needs for cash for investment opportunities. Consequently, we have substantially expanded our credit facilities and created other financing structures and facilities to meet our needs during this period. The more significant changes are discussed below.

Merger with The Coastal Corporation

In January 2001, we merged with The Coastal Corporation. We accounted for the merger as a pooling of interests and converted each share of Coastal common stock and Class A common stock on a tax-free basis into 1.23 shares of our common stock. We also exchanged Coastal's outstanding convertible preferred stock for our common stock on the same basis as if the preferred stock had been converted into Coastal common stock immediately prior to the merger. We issued a total of 271 million shares, including 4 million shares issued to holders of Coastal stock options. The total value of the transaction was approximately $24 billion, including $7 billion of assumed debt and preferred equity.

Coastal is a diversified energy holding company. It is engaged, through its subsidiaries and joint ventures, in natural gas transmission, storage, gathering, processing and marketing; natural gas and oil exploration and production; petroleum refining, marketing and distribution; chemicals production; power production; and coal mining. Coastal owns interests in approximately 18,000 miles of natural gas pipelines extending across the midwestern and the Rocky Mountain areas of the U.S. has proved reserves of 3.6 Tcfe. Coastal also has international and domestic interests in natural gas and oil producing properties, power generation plants, and crude oil refining facilities.

Purchase of Texas Midstream Operations

In late December 2000, we completed our purchase of PG&E's Texas Midstream operations for $887 million, including the assumption of $527 million of debt. We accounted for this acquisition as a purchase. The assets acquired consist of 7,500 miles of natural gas transmission and natural gas liquids pipelines that transport approximately 2.8 Bcf/d, nine natural gas processing plants that process 1.5 Bcf/d, and rights to 7.2 Bcf of natural gas storage capacity. These assets serve a majority of the metropolitan areas and the largest industrial load centers in Texas, as well as numerous natural gas trading hubs. These assets also create a physical link between our EPNG and TGP systems. In March 2001, Field Services sold some of these acquired natural gas liquids transportation and fractionation assets to Energy Partners. The assets sold include more than 600 miles of natural gas liquids gathering and transportation pipelines and three fractionation plants located in south Texas.

In December 2000, to comply with a Federal Trade Commission order, we sold our interest in Oasis Pipeline Company. Proceeds from the sale were $22 million and we recognized an extraordinary loss of $19 million, net of income taxes of $9 million.

Merger with Sonat Inc.

In October 1999, we completed our merger with Sonat. In the merger, we issued one share of our common stock for each share of Sonat common stock. Total shares issued were approximately 110 million shares. In connection with a Federal Trade Commission order related to this merger, we sold our East Tennessee Natural Gas Company and Sea Robin Pipeline Company as well as our one-third interest in Destin Pipeline Company. Proceeds from the sales were approximately $616 million and we recognized an extraordinary gain of $89 million, net of income taxes of $60 million. We accounted for the merger as a pooling of interests.

Merger-Related Costs and Asset Impairment Charges

As we have integrated the activities and operations of our mergers and acquisitions, we have incurred, and will continue to incur, charges that will have a significant impact on our results of operations, financial position and cash flows. These costs, which are of a non-recurring nature, will include employee severance, retention, and transition charges; write-offs or write-downs of duplicate assets; charges to relocate assets and employees; contract termination charges; and charges to align accounting policies and practices.

During the three year period ended December 31, 2000, we incurred charges related to the mergers with Coastal, Sonat, and Zilkha Energy. In September 2000, we announced a plan to geographically consolidate our pipeline operations with Coastal's following the completion of our Coastal merger. Under the consolidation plan, El Paso Natural Gas Company's operations will be relocated from El Paso, Texas to Colorado Springs, Colorado, and ANR Pipeline Company, a subsidiary of Coastal, will be relocated from Detroit, Michigan, to Houston, Texas. Along with this consolidation, we will also conduct numerous relocations among our various operating sites. All relocations under these plans are expected to be completed by mid-year 2001.

Upon our merger with Coastal, we issued approximately 4 million shares of our common stock in exchange for Coastal employee, former employee, and outside director stock options. The total charge in connection with this exchange was approximately $278 million and will be included in our combined operations during the first quarter of 2001.

As a result of our merger with Coastal, we will also be required to sell our Midwestern pipeline system. Proceeds from the sale are expected to be approximately $90 million, and will result in a before tax gain of approximately $50 million. We expect to complete this sale in the second quarter of 2001.

Additionally, in the first quarter of 2001 Energy Partners sold its interest in several offshore assets. These sales consisted of interests in seven natural gas pipeline systems, a dehydration facility and two offshore platforms. Proceeds from these sales were approximately $135 million and resulted in a loss to the partnership of approximately $23 million. As additional consideration for these sales, we committed to pay Energy Partners a series of payments totaling $29 million. This amount, as well as our proportional share of the losses on the sale of the partnership's assets, will be recorded as a charge in our income statement in the first quarter of 2001.

We do not anticipate the impact of the sale of our Midwestern system or the transactions by or with Energy Partners to have a material effect on our ongoing financial position, operating results, or cash flows.

On January 30, 2001, we completed an employee restructuring, which resulted in the reduction of 3,285 full-time positions through a combination of early retirements and terminations. These reductions occurred across all locations and business segments. These actions resulted in severance and termination charges, retention payments for employees retained in the combined organization, and the acceleration of employee benefits under existing benefit plans. Total charges in connection with these actions are estimated to be approximately $890 million with a majority being recorded in the first quarter of 2001.

The total cost of our merger-related activities, as well as additional charges we will incur as we complete our evaluations of the contracts, operating assets, and accounting policies of the combined organization could range between $1.6 billion and $2 billion. This estimate is based on the costs we expect to record in the first quarter of 2001 and our preliminary estimates of additional costs we will incur. We expect that most of these charges will be recorded in 2001.

Also during the three year period ended December 31, 2000, we incurred a variety of asset impairment charges ranging from those as a result of rate filings within our regulated pipelines to write-downs of operating plants and contracts that were determined to be impaired. We also recorded write-downs of capitalized costs of our natural gas and oil properties under the full cost method of accounting in both 1998 and 1999.

Our merger-related costs and asset impairment charges are reflected in the results of operations discussed below for each of our segments. The table below provides a summary of our merger-related costs and asset impairment charges by each of our business segments, and in total, for each of the three years ended December 31:

	2000	1999	1998
		(In millions)	
Merger-related costs and asset impairment charges			
Pipelines	$—	$ 90	$ —
Merchant Energy	—	67	—
Field Services	11	8	—
Production	—	31	15
Segment total	11	196	15
Corporate and other	80	361	—
Consolidated total	$91	$557	$ 15
Ceiling test charges—Production	$—	$352	$1,035

Segment Results of Operations

Our business activities are segregated into four segments: Pipelines, Merchant Energy, Field Services, and Production. These segments are strategic business units that offer a variety of different energy products and services. During the fourth quarter of 2000, we combined our International segment with our Merchant Energy segment to reflect the ongoing globalization of the Merchant Energy strategy and its operating activities. In addition, these results do not include the impact of our merger with Coastal, which will not be reflected in our results of operations until 2001. Results of PG&E's Texas Midstream operations were reflected in our results as of the purchase date. We manage each of our segments separately as each requires different technology and marketing strategies. Since earnings on equity investments can be a significant component of earnings in several of our segments, we evaluate segment performance based on earnings before interest expense and taxes, or EBIT, instead of operating income.

To the extent possible, results of operations have been reclassified to conform to the current business segment presentation, although such results are not necessarily indicative of the results which would have been achieved had the revised business segment structure been in effect during those periods. Operating revenues and expenses by segment include intersegment revenues and expenses which are eliminated in consolidation. Because changes in energy commodity prices have a similar impact on both our operating revenues and cost of products sold from period to period, we believe that gross margin (revenue less cost of sales) provides a more accurate and meaningful basis for analyzing operating results for the Merchant Energy and the Field Services segments. For a further discussion of the individual segments, see Item 8, Financial Statements and Supplementary Data, Note 15.

The following table presents EBIT by segment and in total, including the merger-related costs and asset impairment charges discussed above, for each of the three years ended December 31:

	2000	1999	1998
		(In millions)	
Earnings Before Interest Expense and Income Taxes			
Pipelines	$ 822	$ 719	$ 811
Merchant Energy	563	3	28
Field Services	102	85	76
Production	196	(257)	(936)
Segment EBIT	1,683	550	(21)
Corporate and other expenses, net	(133)	(359)	(31)
Consolidated EBIT	$1,550	$ 191	$ (52)

Pipelines

Our Pipeline segment operates our interstate pipeline businesses. Each of this segment's pipeline systems operates under a separate tariff that governs its operations and rates. Operating results for our pipeline systems have generally been stable because the majority of the revenues are based on fixed demand charges. As a result, we expect changes in this aspect of our business to be primarily driven by regulatory actions and contractual events. Commodity or throughput-based revenues account for a smaller portion of our operating results. These revenues vary from period to period, and system to system, and are impacted by factors such as weather, operating efficiencies, competition from other pipelines, and to a lesser degree, fluctuations in natural gas prices. Results of operations of our Pipeline segment were as follows for each of the three years ending December 31:

	2000	1999	1998
		(In millions)	
Operating revenues	$ 1,697	$ 1,771	$ 1,696
Operating expenses	(943)	(1,103)	(944)
Other income	68	51	59
EBIT	$ 822	$ 719	$ 811
Total throughput (BBtu/d)	11,842	11,290	11,401

Year Ended December 31, 2000 Compared to Year Ended December 31, 1999

Operating revenues for the year ended December 31, 2000, were $74 million lower than the same period in 1999. This decrease was due to the impact of our sales of the East Tennessee Pipeline and Sea Robin systems in the first quarter of 2000, which we were required to sell under an FTC order as a condition to completing our Sonat merger. Also contributing to the decrease was a favorable resolution of regulatory issues in the first quarter of 1999 on TGP, lower rates following SNG's May 2000 rate case settlement, lower revenues from contracts for relinquished capacity on EPNG, and the elimination of the minimum bill provision on our Elba Island facility following FERC's approval of Elba Island's reactivation in the first quarter of 2000. Additionally, the impact of customer settlements and contract terminations in 2000 and resolutions of customer imbalance issues in 1999 on TGP contributed to the decrease. Partially offsetting these decreases were higher revenues from transportation and other services provided on each of our transmission systems due to improved average throughput in 2000, higher realized prices on pipeline gas sales, and revenues from the January 2000 acquisition of Crystal Gas Storage, Inc., prior to its sale to Energy Partners in September 2000.

Operating expenses for the year ended December 31, 2000, were $160 million lower than the same period in 1999. The decrease was due to cost efficiencies following our merger with Sonat, lower operating costs on our East Tennessee Pipeline and Sea Robin systems as a result of their sale in March 2000, and the favorable impact of FERC's authorization to reactivate SNG's Elba Island facility in the first quarter of 2000. Also contributing to the decrease was the 1999 resolution of a contested rate matter with a customer of EPNG, severance and termination charges incurred as a result of our Sonat merger, and the impairment of several SNG expansion projects, all occurring in 1999. Additionally, estimated future environmental costs and write-offs of duplicate information technology assets in 1999 on SNG following our merger with Sonat contributed to the decrease. The decrease was partially offset by the impact of unfavorable producer and shipper settlements on EPNG as well as revised estimates of regulatory recoveries on EPNG and higher utility costs in 2000.

Other income for the year ended December 31, 2000 was $17 million higher than the same period in 1999. The increase was due to higher earnings on Citrus Corp. as a result of a one-time benefit recorded in 2000, as well as gains on the sale of non-pipeline assets in the third quarter of 2000. The increase was partially offset by the favorable settlement of a regulatory issue in 1999, the elimination of an asset for the future recovery of costs of the Elba Island facility, and a lower allowance for funds used during construction as a result of less expansion and construction activity in 2000.

Year Ended December 31, 1999 Compared to Year Ended December 31, 1998

Operating revenues for the year ended December 31, 1999, were $75 million higher than 1998. This increase was due to the favorable resolution of regulatory issues during 1999 on TGP coupled with a downward revision in 1998 of the amount of recoverable interest on TGP's GSR costs. Also contributing to the increase were higher revenues from transportation and other services, an increase in firm transportation revenues on the SNG system associated with expansion projects, resolutions of TGP's customer imbalance issues, and higher operational gas sales. These increases were partially offset by lower system throughput on the TGP system in 1999, the favorable resolution in 1998 of a contested rate matter on the MPC system related to its rate methodology, and higher non-transportation revenues in 1998 on the SNG system.

Operating expenses for the year ended December 31, 1999 were $159 million higher than 1998. The increase was due to severance and termination charges incurred as a result of our merger with Sonat, the impairment of several SNG expansion projects, an increase in estimated environmental costs, and write-offs of duplicate information technology assets, all occurring in 1999. Also contributing to the increase were higher general and administrative costs on all systems, higher depreciation from expansion projects on SNG, and the unfavorable 1999 resolution of a contested rate matter with a customer of EPNG. Partially offsetting these increases were revised estimates of regulatory recoveries on EPNG.

Other income for the year ended December 31, 1999, was $8 million lower than 1998. The decrease was primarily due to lower equity earnings on Destin Pipeline Company in 1999, partially offset by an increase in 1999 interest income on a Destin-related debt issuance during the latter part of 1998. We were required to sell Destin as a result of our merger with Sonat.

Merchant Energy

Merchant Energy is a market maker involved in a wide range of activities in the wholesale energy market place, including trading and risk management, asset ownership and financial services. Each of the markets served by Merchant Energy is highly competitive, and is influenced directly or indirectly by energy market economics.

Merchant Energy's trading and risk management activities provide sophisticated energy trading and energy management solutions for its customers and affiliates involving primarily natural gas and power. Within its trading and risk management operations, Merchant Energy originates transactions with its customers to assist them with energy supply aggregation, storage and transportation management, as well as valuation and risk management. Merchant Energy maintains a substantial trading portfolio that balances its position risk across multiple commodities and over seasonally fluctuating energy demands. During 2000, U.S. energy supply and demand resulted in substantial volatility in the energy markets that significantly impacted Merchant Energy's earnings opportunities. This volatility is expected to continue for 2001, although not necessarily at the same levels we experienced in 2000.

Merchant Energy is a provider of power and natural gas to the state of California. During the latter half of 2000, and continuing into 2001, California has experienced sharp increases in natural gas prices and wholesale power prices due to energy shortages resulting from the concurrence of a variety of circumstances, including unusually warm summer weather followed by high winter demand, low gas storage levels, poor hydroelectric power conditions, maintenance downtime of significant generation facilities, and price caps that discouraged power movement from other nearby states into California.

The increase in power prices caused by the imbalance of natural gas and power supply and demand coupled with electricity price caps imposed on rates allowed to be charged to California electricity customers has resulted in large cash deficits to the two major California utilities, Southern California Edison and Pacific Gas and Electric. As a result, both utilities have defaulted on payments to creditors and have accumulated substantial under collections from customers, which has resulted in their credit ratings being downgraded in 2001 from above investment grade to below investment grade. The utilities filed for emergency rate increases with the California Public Utilities Commission and are working with the state authorities to restore the companies' financial viability. We have historically been one of the largest suppliers of energy to California, and we are actively participating with all parties in California to be a part of a long-term, stable solution to California's energy needs. As of March 2001, Merchant Energy believes its exposure for sales of power and gas to the state of California, including receivables related to its interest in California power plant investments, is approximately $50 million, net of credit reserves to reflect market uncertainties.

Merchant Energy's asset ownership activities include global power plants and the power facilities owned and managed on behalf of Chaparral. Its asset-based businesses include power plants in 16 countries. Merchant Energy is also actively involved in developing a global LNG operation. During 2000, Merchant Energy earned $80 million in fee based revenue from Chaparral and was reimbursed $20 million for operating expenses. We expect the 2001 fee based revenue to increase to approximately $147 million based on the growth in the Chaparral asset portfolio.

In the financial services area, Merchant Energy owns EnCap and Enerplus, and conducts other energy financing activities. EnCap manages three separate oil and natural gas investment funds in the U.S., and serves as an investment advisor to one fund in Europe. EnCap also facilitates investment in emerging energy companies and earns a return from these investments. In 2000, Merchant Energy acquired Enerplus, a Canadian investment management company through which it conducts fund management activities similar to EnCap, but in Canada. Below are Merchant Energy's operating results and an analysis of those results for each of the three years ended December 31:

	2000	1999	1998
	(In millions)		
Trading gross margin	$ 406	$ 91	$ 71
Operating and other revenues	291	119	58
Operating expenses	(264)	(301)	(166)
Other income	130	94	65
EBIT	$ 563	$ 3	$ 28

Volumes

	2000	1999	1998
	(Excludes intrasegment transactions)		
Physical			
Natural Gas (BBtue/d)	6,899	6,713	7,089
Power (MMWh)	113,652	79,361	55,210
Petroleum (MBbls)	7,772	4,990	21,716
Financial Settlements (Bbtue/d)	98,574	68,678	31,793

Year Ended December 31, 2000 Compared to Year Ended December 31, 1999

Trading gross margin represents revenue from physical energy commodity sales less costs of these sales as well as results from financial trading activities. For the year ended December 31, 2000, trading gross margin was $315 million higher than the same period in 1999. Commodity marketing and trading margins increased due to significant price volatility in natural gas and power markets which increased the value of our trading portfolio during 2000. Also contributing to the increase was higher income from power transactions originated in 2000 versus 1999. These increases were partially offset by natural gas transactions originated in 1999.

Operating and other revenues represent all operating and other revenues, excluding revenue from energy commodity sales. For the year ended December 31, 2000, these revenues were $172 million higher than the same period in 1999. The increase was due to higher asset management fees earned from Chaparral, which began operations during the fourth quarter of 1999, the consolidation of a Brazilian power project in the latter part of 1999, and higher income on the West Georgia power project, a seasonal peaking facility, which began operating in June 2000. Encap's financial services activities in 2000, and the acquisition of Enerplus in March 2000 also contributed to the increase.

Operating expenses for the year ended December 31, 2000, were $37 million lower than the same period in 1999. The decrease was due to higher reimbursements in 2000 of general and administrative costs relating to Chaparral, a 1999 charge to eliminate a minority investor in Sonat's marketing joint venture following the Sonat merger, and 1999 asset writedowns and charges to conform and consolidate accounting practices and policies with those of Sonat following the merger. The decrease was partially offset by higher general and administrative expenses and project development costs relating to international projects in 2000.

Other income for the year ended December 31, 2000, was $36 million higher than the same period in 1999. The increase was due to higher earnings from power projects and investments, primarily CE Generation, which was acquired in March 1999, as well as the benefit realized from the formation of our East Asia Power joint venture in March 2000. Also contributing to the increase was a settlement received from our Indonesian project in May 2000, and higher interest income. These increases were partially offset by lower equity earnings from investments in various international projects, primarily our investment in East Asia Power in the Philippines.

Year Ended December 31, 1999 Compared to Year Ended December 31, 1998

Trading gross margin for the year ended December 31, 1999, was $20 million higher than the same period in 1998. Commodity marketing and trading margins increased due to transactions originated in 1999, partially offset by a decrease in trading margins in 1999.

Operating and other revenues for the year ended December 31, 1999, were $61 million higher than the same period in 1998. The increase was primarily due to management fees earned from Chaparral, revenues from a Brazilian power project consolidated during the latter part of 1999, and revenues from consolidated power generation facilities acquired in December 1998.

Operating expenses for the year ended December 31, 1999, were $135 million higher than the same period in 1998. The increase was due to higher operating costs associated with an increase in power activities, operating expenses on consolidated power generation facilities acquired in December 1998, a 1999 charge to eliminate a majority interest in Sonat's marketing joint venture following the Sonat merger, and 1999 asset writedowns and charges to conform and consolidate accounting practices and policies with those of Sonat following the merger. Also contributing to the increase were higher general and administrative costs and higher operating costs from our Brazilian power project. The increases were partially offset by lower project development costs on international projects in 1999.

Other income for the year ended December 31, 1999, was $29 million higher than the same period in 1998. The increase was due to higher earnings from power projects and investments, primarily CE Generation, higher interest income, and 1999 equity swap gains recognized on our CAPSA project. These increases were partially offset by 1998 gains on the sale of project-related activities and surplus power equipment.

Field Services

Field Services provides a variety of services for the midstream component of our operations, including gathering and treating of natural gas, processing and fractionation of natural gas, natural gas liquids and natural gas derivative products, such as butane, ethane, and propane. A subsidiary of Field Services also serves as the general partner of Energy Partners, a publicly traded, master limited partnership. As the general partner, Field Services earns a combination of management fees and partner distributions for services rendered to Energy Partners. Field Services attempts to balance its earnings from these activities through a combination of contractually based and market based services.

The gathering and treating operations earn margins substantially from fee-based services. This means revenues are the product of a market price, usually related to the monthly natural gas price index, and the volume gathered. During most of 2000, Field Services hedged a substantial amount of the risk associated with the changes in natural gas prices by entering into forward natural gas derivatives.

Processing and fractionation operations earn a margin based on both fee-based contracts and make-whole contracts. Make-whole contracts allow us to retain the extracted liquid products and to return to the producer a Btu equivalent amount of natural gas. During periods when natural gas and liquid prices are volatile, Field Services may be at greater price risk under its make-whole contracts. Make-whole contracts constitute a greater portion of the operating contracts acquired in late December in connection with our acquisition of PG&E's Texas Midstream operations.

Field Services' operating results and an analysis of those results are as follows for each of the three years ended December 31:

	2000	1999	1998
		(In millions)	
Gathering and treating margin	$ 178	$ 162	$ 157
Processing margin	69	44	48
Other margin	2	1	3
Total gross margin	249	207	208
Operating expenses	(173)	(169)	(146)
Other income	26	47	14
EBIT	$ 102	$ 85	$ 76
Volumes and prices			
Gathering and treating			
Volumes (BBtu/d)	3,952	4,279	4,172
Prices ($/MMBtu)	$ 0.17	$ 0.14	$ 0.13
Processing			
Volumes (inlet BBtu/d)	1,065	1,032	1,014
Prices ($/MMBtu)	$ 0.18	$ 0.12	$ 0.13

Year Ended December 31, 2000 Compared to Year Ended December 31, 1999

Total gross margin for the year ended December 31, 2000, was $42 million higher than the same period in 1999. Gathering and treating margins increased due to higher average gathering rates, predominantly in the San Juan Basin, which are substantially indexed to natural gas prices and higher average condensate prices. The higher margin in 2000 was partially offset by lower gathering and treating volumes due to the sale of El Paso Intrastate Alabama, a gathering system in the coal-bed methane producing regions of Alabama, to Energy Partners in March 2000. Processing margins increased due to higher liquids prices in 2000 and the acquisition, in April 2000, of an interest in the Indian Basin processing assets.

Operating expenses for the year ended December 31, 2000, were $4 million higher than the same period in 1999 due to higher depreciation and amortization from assets transferred from EPNG to Field Services following a FERC order, as well as the December 2000 impairment charge related to the Needle Mountain processing facility due to unrecoverability of costs. The increase was partially offset by the impairment of gathering assets in 1999, lower costs for labor and benefits, and cost recoveries from managed facilities.

Other income for the year ended December 31, 2000, was $21 million lower than the same period in 1999. The decrease was primarily due to net gains in 1999 from the sale of our interest in the Viosca Knoll gathering system to Energy Partners in June 1999, as well as lower equity earnings in 2000 following the sale of our interest in Viosca Knoll.

Year Ended December 31, 1999 Compared to Year Ended December 31, 1998

Total gross margin for the year ended December 31, 1999, was $1 million lower than the same period in 1998. Gathering and treating margins increased due to higher volumes and average gathering rates, which are substantially indexed to natural gas prices, partially offset by the elimination of margins on assets in the Anadarko Basin that were sold in September 1998. Processing margins decreased due to lower liquids prices and the sale of two processing facilities in 1999.

Operating expenses for the year ended December 31, 1999, were $23 million higher than the same period in 1998. The increase was due to higher shared services allocations in 1999, the impairment of gathering assets in the fourth quarter of 1999, and an increase in depreciation and amortization resulting from acquisitions.

Other income for the year ended December 31, 1999, was $33 million higher than the same period in 1998. The increase was due to higher earnings from investments, primarily Energy Partners, as well as a gain recorded in 1999 from the sale of our interest in Viosca Knoll.

Production

Production's operating results are driven by a variety of factors including its ability to locate and develop economic reserves, extract those reserves with minimal production costs, sell the products at attractive commodity prices, and operate at the lowest cost level possible.

Over the past few years, Production has been successful in replacing its production with new, relatively low cost reserves. In addition, Production has also been successful in efficiently extracting its reserves and maintaining a low overall cost structure. In 1998, Production restructured its business in response to depressed market conditions and did so again in 1999 following the Sonat merger. Both of these efforts were successful in reducing overhead and administrative costs.

Production engages in hedging activities on its natural gas and oil production in order to stabilize cash flows and reduce the risk of downward commodity price movements on sales of its production. This is achieved through natural gas and oil swaps. Typically, a higher percentage of production is hedged in the current year and then decreases each year thereafter. Production's hedged position is closely monitored and evaluated in an effort to achieve its earnings objectives and reduce the risks associated with spot-market price volatility. In 2000, realized prices for natural gas and oil sales were lower than those that could have been realized had the production been sold at spot-market prices. However, this hedging strategy produced a relatively stable revenue stream that resulted in expected rates of return. For 2001, we anticipate hedging approximately 75 percent of our production, which includes our estimates for Coastal's 2001 production.

These factors, while not the only ones influencing results, usually impact performance from period to period. Below are the operating results and analysis of these results for each of the three years ending December 31.

	2000	1999	1998
		(In millions)	
Natural gas	$ 425	$ 380	$ 440
Oil, condensate and liquids	92	90	101
Other	5	3	(6)
Total operating revenues	522	473	535
Operating expenses	(326)	(731)	(1,474)
Other income	—	1	3
EBIT	$ 196	$ (257)	$ (936)
Volumes and prices			
Natural gas			
Volumes (MMcf)	187,845	185,968	225,653
Average realized prices ($/Mcf)	$ 2.26	$ 2.05	$ 1.95
Oil, condensate, and liquids			
Volumes (MBbls)	5,138	5,825	8,327
Average realized prices ($/Bbl)	$ 17.98	$ 15.46	$ 12.22

Year Ended December 31, 2000 Compared to Year Ended December 31, 1999

Operating revenues for the year ended December 31, 2000, were $49 million higher than 1999. The increase was due to higher realized prices for natural gas and oil, condensate, and liquids.

Operating expenses for the year ended December 31, 2000, were $405 million lower than 1999. The decrease was due to full cost ceiling test charges incurred in the first quarter of 1999, decreased 2000 labor costs as a result of an organizational restructuring following our Sonat merger, and 1999 charges to retain Sonat's seismic data in our production operations as a result of the merger. The decrease was partially offset by higher depletion rates in 2000 as a result of increased future development costs in 2000 versus 1999.

Year Ended December 31, 1999 Compared to Year Ended December 31, 1998

Total operating revenues for the year ended December 31, 1999, were $62 million lower than 1998. The decrease in natural gas and oil, condensate, and liquids revenues was primarily due to the sales of properties during 1998, partially offset by an increase in realized prices in 1999. The increase in other revenues resulted from a favorable contractual settlement in 1999.

Operating expenses for the year ended December 31, 1999, were $743 million lower than 1998 primarily due to lower full cost ceiling test charges in 1999 versus the charges incurred in 1998, along with lower production levels in 1999. Also contributing to the decrease were lower operating and maintenance expenses due to property dispositions in 1998 and efficiencies created from Production's 1998 reorganization of its operations. These decreases were partially offset by charges to retain Sonat's seismic data in our production operations as a result of the Sonat merger.

Other income for the year ended December 31, 1999, was $2 million lower than 1998 due primarily to a net gain on the sale of non-operating assets during the third quarter of 1998.

Corporate and other expenses, net

Year Ended December 31, 2000 Compared to Year Ended December 31, 1999

Corporate and other expenses for the year ended December 31, 2000, were $226 million lower than 1999. The decrease was primarily due to higher costs related to our merger with Sonat in 1999, partially offset by costs incurred in 2000 related to our merger with Coastal. Also offsetting the decrease were increased funding commitments to the El Paso Energy Foundation in 2000.

We will incur additional merger-related costs in 2001 as a result of our merger with Coastal.

Year Ended December 31, 1999 Compared to Year Ended December 31, 1998

Net corporate expenses for the year ended December 31, 1999, were $328 million higher than 1998 primarily due to charges in 1999 related to our merger with Sonat including the accelerated amortization of certain employee benefits; legal, accounting, and financial advisory costs; employee severance and retention costs; and incremental costs incurred in combining office facilities following the merger. This increase was partially offset by costs incurred in 1998 from the introduction of our power services activities and higher recurring equity compensation charges in 1998.

Interest and Debt Expense

Year Ended December 31, 2000 Compared to Year Ended December 31, 1999

Interest and debt expense for the year ended December 31, 2000, was $85 million higher than 1999 primarily due to $900 million of increased borrowings under a combination of short-term and long-term programs by El Paso to fund capital expenditures, acquisitions, and other investing activities, and $46 million of increased interest expense on borrowings from Chaparral in 2000.

Year Ended December 31, 1999 Compared to Year Ended December 31, 1998

Interest and debt expense for the year ended December 31, 1999, was $66 million higher than 1998 primarily due to increased borrowings by El Paso of $1.8 billion to fund capital expenditures, acquisitions, and other investing activities offset by higher capitalized interest in 1999 from higher project investment and development primarily in Production and Merchant Energy.

Income Tax Expense (Benefit)

Income tax expense (benefit) for the years ended December 31, 2000, 1999, and 1998, was $286 million, $(81) million, and $(170) million. These amounts resulted in effective tax rates of 33 percent, 25 percent, and 36 percent. Differences in our effective tax rates from the statutory tax rate of 35 percent were primarily a result of the following factors:

- state income taxes;
- earnings from unconsolidated equity investees where we anticipate receiving dividends;
- foreign income, not taxed in the U.S., but taxed at foreign tax rates;
- the utilization of deferred credits on loss carryovers;
- the non-deductible portion of merger-related costs; and
- non-deductible dividends on the preferred stock of a subsidiary.

For a reconciliation of the statutory rate of 35 percent to the effective rates in each of the three years ended December 31, 2000, see Item 8, Financial Statements and Supplementary Data, Note 4.

Minority Interest

Year ended December 31, 2000 Compared to Year ended December 31, 1999

Minority interest for the year ended December 31, 2000, was $83 million higher than in 1999 primarily due to a full year of costs associated with the preferred interest in Trinity River Associates, L.L.C., formed in June 1999. Also contributing to the increase were costs associated with a preferred interest in Clydesdale Associates, L.P. and distributions associated with preferred securities of El Paso Energy Capital Trust IV, both of which were formed in May 2000.

Year ended December 31, 1999 Compared to Year ended December 31, 1998

Minority interest for the year ended December 31, 1999, was $24 million higher than in 1998 as a result of costs associated with a preferred interest in Trinity River Associates, L.L.C. in 1999, coupled with a full year of dividends on preferred securities of El Paso Energy Capital Trust I issued in March 1998.

Liquidity and Capital Resources

Cash From Operating Activities

Net cash used in our operating activities was $1,040 million for the year ended December 31, 2000, compared to net cash provided by operating activities of $501 million for 1999. The increase in cash used in operations was primarily a result of cash expended in our price risk management activities as well as higher trading receivables and payables related to the substantial growth in our trading portfolio and higher prices in the energy commodity markets. We also had higher interest payments in 2000 primarily related to higher long-term and short-term debt balances, and higher 2000 income tax payments as a result of higher state and foreign income tax payments. Partially offsetting these increases were higher payments in 1999 for merger-related costs and activities versus merger-related payments made in 2000, and higher cash generated in 2000 from our pipeline, field services, and production operations. In 2001, we expect to pay significant amounts related to our Coastal merger and expect cash demands from our expanded Merchant Energy activities to continue. Offsetting this should be higher cash generated from our expanded operations following our merger with Coastal.

Cash From Investing Activities

Net cash used in our investing activities was $1,553 million for the year ended December 31, 2000. Our investing activities principally consisted of additions to joint ventures and equity investments, including an increase in our Chaparral equity investment, the purchase of an additional 18.5% interest in an Argentine company, CAPSA, the purchase of an investment in a Korean power company, Korea Independent Energy Corporation (formerly Hanwha Energy Co., Ltd), and a note receivable from Quanta Investors, L.L.C., a company formed to hold various telecommunications assets. Other investing activities in 2000 included the acquisitions of PG&E's Texas Midstream operations, Crystal Gas Storage, Inc., and Enerplus Global Management. We also purchased the All-American pipeline assets, an interest in the Indian Basin gas processing plant assets, and had expenditures for expansion and construction projects. Cash inflows from investment related activities included proceeds from the sales of our East Tennessee pipeline system, Sea Robin pipeline system, El Paso Intrastate-Alabama pipeline system, our one-third interest in the Destin pipeline system, and the West Georgia Generating Company. We also received proceeds from the formation of our East Asia Power joint venture and the repayment of a note receivable by Chaparral.

Cash From Financing Activities

Net cash provided by our financing activities was $2,736 million for the year ended December 31, 2000. Cash provided from our financing activities included revolving credit borrowings, the issuance of long-term debt, the sale of an interest in Clydesdale Associates, L.P., the issuance of preferred securities of El Paso Energy Capital Trust IV, and notes payable to Chaparral. During 2000, we repaid short-term borrowings, paid dividends, and retired long-term debt.

Liquidity

We rely on cash generated from internal operations as our primary source of liquidity, supplemented by our available credit facilities and commercial paper programs. The availability of borrowings under our credit agreements is subject to specified conditions, which we believe we currently meet. These conditions include compliance with the financial covenants and ratios required by our agreements, absence of default under these agreements, and continued accuracy of our representations and warranties (including the absence of any material adverse changes since the specified dates).

We expect that future funding for our working capital needs, capital expenditures, acquisitions, other investing activities, long-term debt retirements, payments of dividends and other financing expenditures will be provided by internally generated funds, commercial paper issuances, available capacity under existing credit facilities, and the issuance of new long-term debt, trust securities, or equity. For a discussion of our financing arrangements, see Item 8, Financial Statements and Supplementary Data, Note 9.

Commitments and Contingencies

See Item 8, Financial Statements and Supplementary Data, Note 11, for a discussion of our commitments and contingencies.

At December 31, 2000, we had capital and investment commitments of $1.2 billion primarily relating to our production, pipeline, and international power activities. Our other planned capital and investment projects are discretionary in nature, with no substantial capital commitments made in advance of the actual expenditures.

New Accounting Pronouncements Not Yet Adopted

See Item 8, Financial Statements and Supplementary Data, Note 1, for a discussion of new accounting pronouncements we have not yet adopted.

RISK FACTORS AND CAUTIONARY STATEMENT FOR PURPOSES OF THE "SAFE HARBOR" PROVISIONS OF THE PRIVATE SECURITIES LITIGATION REFORM ACT OF 1995

This report contains or incorporates by reference forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995. Where any forward-looking statement includes a statement of the assumptions or bases underlying the forward-looking statement, we caution that, while we believe these assumptions or bases to be reasonable and to be made in good faith, assumed facts or bases almost always vary from the actual results, and differences between assumed facts or bases and actual results can be material, depending upon the circumstances. Where, in any forward-looking statement, we or our management express an expectation or belief as to future results, that expectation or belief is expressed in good faith and is believed to have a reasonable basis. We cannot assure you, however, that the statement of expectation or belief will result or be achieved or accomplished. The words "believe," "expect," "estimate," "anticipate" and similar expressions will generally identify forward-looking statements.

With this in mind, you should consider the following important factors that could cause actual results to differ materially from those expressed in any forward-looking statement made by us or on our behalf:

We operate in highly competitive industries.

Most of the natural gas and natural gas liquids we transport, gather, process and store are owned by third parties. As a result, the volume of natural gas and natural gas liquids involved in these activities depends on the actions of those third parties, and is beyond our control. Further, the following factors, most of which are beyond our control, may unfavorably impact our ability to maintain or increase current transmission, storage, gathering, processing, and sales volumes and rates, to renegotiate existing contracts as they expire or to remarket unsubscribed capacity:

- future weather conditions, including those that favor hydroelectric generation or other alternative energy sources;
- price competition;
- drilling activity and supply availability;
- expiration of significant contracts; and
- service area competition, especially due to current excess pipeline capacity into California and the Midwest.

If we are unable to compete with services offered by other energy enterprises which may be larger, offer more services, and possess greater resources, our future profitability may be negatively impacted.

The revenues of our pipeline businesses are generated under contracts that must be renegotiated periodically.

Substantially all of our pipeline subsidiaries' revenues are generated under natural gas transportation contracts which expire periodically and must be renegotiated and extended or replaced. Although we actively pursue the renegotiation, extension and/or replacement of these contracts, we cannot assure you that we will be able to extend or replace these contracts when they expire or that the terms of any renegotiated contracts will be as favorable as the existing contracts.

In particular, our ability to extend and/or replace transportation contracts could be harmed by factors we cannot control, including:

- the proposed construction by other companies of additional pipeline capacity in markets served by our interstate pipelines;
- changes in state regulation of local distribution companies, which may cause them to negotiate short-term contracts;
- reduced demand due to higher natural gas prices;

- the availability of alternative energy sources or supply points; and
- the viability of our expansion projects.

If we are unable to renew, extend or replace these contracts or if we renew them on less favorable terms, we may suffer a material reduction in our revenues and earnings.

Fluctuations in energy commodity prices could adversely affect our business.

If natural gas prices in the supply basins connected to our pipeline systems are higher than prices in other natural gas producing regions, especially Canada, our ability to compete with other transporters may be negatively impacted. Revenues generated by our gathering and processing contracts depend on volumes and rates, both of which can be affected by the prices of natural gas and natural gas liquids. The success of our gathering and processing operations in the offshore Gulf of Mexico is subject to continued development of additional oil and natural gas reserves in the vicinity of our facilities and our ability to access additional reserves to offset the natural decline from existing wells connected to our systems. A decline in energy prices could precipitate a decrease in these development activities and could cause a decrease in the volume of reserves available for gathering and processing through our offshore facilities. Fluctuations in energy prices, which may impact gathering rates and investments by third parties in the development of new oil and natural gas reserves connected to our gathering and processing facilities, are caused by a number of factors, including:

- regional, domestic and international supply and demand;
- availability and adequacy of transportation facilities;
- energy legislation;
- federal and state taxes, if any, on the sale or transportation of natural gas and natural gas liquids; and
- abundance of supplies of alternative energy sources.

If there are reductions in the average volume of the natural gas and natural gas liquids we transport, gather and process for a prolonged period, our results of operations and financial position could be significantly, negatively affected.

The rates we are able to charge our customers may be reduced by governmental authorities.

Our pipeline businesses are regulated by the FERC and various state and local regulatory agencies. In particular, the FERC generally limits the rates we are permitted to charge our customers for interstate natural gas transportation and, in some cases, sales of natural gas. If the rates we are permitted to charge our customers for use of our regulated pipelines are lowered, the profitability of our pipeline businesses may be reduced.

The success of our oil and natural gas exploration and production businesses is dependent on factors which cannot be predicted with certainty.

The performance of our exploration and production businesses is dependent upon a number of factors that we cannot control. These factors include:

- fluctuations in crude oil and natural gas prices;
- the results of future drilling activity;
- our ability to identify and precisely locate prospective geologic structures and to drill and successfully complete wells in those structures in a timely manner;
- our ability to expand our leased land positions in desirable areas, which often are subject to intensely competitive leasing conditions;
- risks incident to operations of natural gas and oil wells; and
- future drilling, production and development costs, including drilling rig rates.

Estimates of oil and natural gas reserves may change.

Actual production, revenues, taxes, development expenditures, and operating expenses with respect to our reserves will likely vary from our estimates of proved reserves of oil and natural gas, and those variances may be material. The process of estimating oil and natural gas reserves is complex, requiring significant decisions and assumptions in the evaluation of available geological, geophysical, engineering, and economic data for each reservoir or deposit. As a result, these estimates are inherently imprecise. Actual future production, oil and natural gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and natural gas reserves may vary substantially from our estimates. In addition, we may be required to revise the reserve information, downward or upward, based upon production history, results of future exploration and development, prevailing oil and natural gas prices and other factors, many of which will be beyond our control.

The success of our power generation and marketing activities depends on many factors, some of which may be beyond our control.

The success of our international and domestic power projects and power marketing activities, and the amount of the related performance-based management fee paid to us in connection with the Electron financing structure, could be adversely affected by factors beyond our control, including:

- alternative sources and supplies of energy becoming available due to new technologies and interest in self generation and cogeneration;
- uncertain regulatory conditions resulting from the ongoing deregulation of the electric industry in the United States and in foreign jurisdictions;
- our ability to negotiate successfully and enter into, restructure or recontract advantageous long-term power purchase agreements;
- the possibility of a reduction in the projected rate of growth in electricity usage as a result of factors such as regional economic conditions and the implementation of conservation programs;
- the inability of customers to pay amounts owed under power purchase agreements; and
- the increasing price volatility due to deregulation and changes in commodity trading practices.

Our telecommunications business strategy may not be successful.

Our experience in the telecommunications industry is limited, and we cannot assure you that our telecommunications strategy will be successful. Our success depends in part on the evolution of telecommunications as a commodity and our ability to integrate and adapt our facilities and services to keep pace with advances in communications technologies and the new and improved devices and services that result from these changes. In addition, the market for fiber optic capacity and telecommunications services is rapidly evolving, and although we expect demand for these services to grow, we cannot assure you that this growth will occur. Additionally, the price of fiber optic capacity is expected to continue to decline sharply because of the increase in newly installed fiber optic capacity coming on the market and rapid fiber optic equipment technology improvements. Further, a variety of critical issues, including security, reliability, ease and cost of access, creation of a liquid trading market, uncertain governmental regulation, and quality of service remain unresolved and may adversely affect our business. We cannot assure you, therefore, that our telecommunications strategy will be successful.

We cannot assure you that we and Coastal will be successfully combined into a single entity.

If we cannot successfully combine our operations with Coastal, we may experience a material adverse effect on our business, financial condition, or results of operations. Our merger with Coastal involves combining two companies that have previously operated separately. The combining of our companies involves a number of risks, including:

- the diversion of management's attention to the combining of operations;
- difficulties in combining operations and systems;
- difficulties in assimilating and retaining employees;
- challenges in keeping customers; and
- potential adverse short-term effects on operating results and financial position.

Among the factors considered by the board of directors of each company in approving the merger agreement were the opportunities for economies of scale and scope, opportunities for growth and operating efficiencies that could result from the merger. Although we expect our combined company to achieve significant annual savings in operating costs as a result of the merger, we may not be able to maintain the levels of operating efficiency that we each previously achieved or might achieve if we remain separate. Because of difficulties in combining operations, we may not be able to achieve the cost savings and other size-related benefits that we hope to achieve after the merger.

Our use of derivative financial instruments could result in financial losses.

Some of our non-regulated subsidiaries use futures and option contracts traded on the New York Mercantile Exchange, over-the-counter options and price and basis swaps with other natural gas merchants and financial institutions. These instruments are intended to reduce our exposure to short-term volatility in changes in energy commodity prices. We could, however, incur financial losses in the future as a result of volatility in the market values of the underlying commodities, or if one of our counterparties fails to perform under a contract. Furthermore, because the valuation of these financial instruments can involve estimates, changes in the assumptions underlying these estimates can occur, changing our valuation of these instruments and potentially resulting in financial losses. For additional information concerning our derivative financial instruments, see item 7A, Quantitative and Qualitative Disclosures About Market Risks and Item 8, Financial Statements and Supplementary Data, Note 6.

Attractive acquisition and investment opportunities may not be available.

Our ability to grow will depend, in part, upon our ability to identify and complete attractive acquisition and investment opportunities. Opportunities for growth through acquisitions and investments in joint ventures, and the future operating results and success of these acquisitions and joint ventures within and outside the United States may be subject to the effects of, and changes in United States and foreign:

- trade and monetary policies;
- laws and regulations;
- political and economic developments;
- inflation rates;
- taxes; and
- operating conditions.

Our foreign investments involve special risks.

Our activities in areas outside the U.S. are subject to the risks inherent in foreign operations, including:

- loss of revenue, property and equipment as a result of hazards such as expropriation, nationalization, wars, insurrection and other political risk;
- the effects of currency fluctuations and exchange controls, such as devaluations of the foreign currencies and other economic problems; and
- changes in laws, regulations, and policies of foreign governments, including those associated with changes in the governing parties.

Costs of environmental liabilities, regulations and litigation could exceed our estimates.

Our current and former operations involve management of regulated materials and are subject to various environmental laws and regulations. These laws and regulations obligate us to clean up various sites at which petroleum, chemicals, low-level radioactive substances or other regulated materials may have been disposed of or released. Some of these sites have been designated Superfund sites by the EPA under the Comprehensive Environmental Response, Compensation and Liability Act. We are also party to legal proceedings involving environmental matters pending in various courts and agencies.

It is not possible for us to estimate reliably the amount and timing of all future expenditures related to environmental matters because of:

- the difficulty of estimating clean up costs;
- the uncertainty in quantifying liability under environmental laws that impose joint and several liability on all potentially responsible parties;
- the nature of environmental laws and regulations; and
- the possible introduction of future environmental laws and regulations.

Although we believe we have established appropriate reserves for liabilities, including clean up costs, we could be required to set aside additional reserves in the future due to these uncertainties. For additional information concerning our environmental matters, see Item 8, Financial Statements and Supplementary Data, Note 11.

Our operations are subject to operational hazards and uninsured risks.

Our exploration, production, transportation, gathering, and processing operations are subject to the inherent risks normally associated with those operations, including explosions, pollution, the release of toxic substances, fires, and other hazards, each of which could result in damage to or destruction of our facilities or damages to persons and property. If any of these events were to occur, we could suffer substantial losses.

While we maintain insurance against these types of risks to the extent and in amounts that we believe are reasonable, our financial condition and operations could be adversely affected if a significant event occurs that is not fully covered by insurance.

There remain potential liabilities related to the acquisition of El Paso Tennessee Pipeline Co.

The amount of the actual and contingent liabilities we assumed in our merger with El Paso Tennessee in 1996 could vary substantially from the amounts we estimated, which were based upon assumptions which could prove to be inaccurate. If new Tenneco Inc. or Newport News Shipbuilding Inc. (organizations created and distributed to Tenneco Inc. shareholders prior to our acquisition of Tenneco Inc.'s energy businesses in December 1996) were unable or unwilling to pay their respective liabilities, a court could require us, under legal theories which may or may not be applicable to the situation, to assume responsibility for those obligations. If we were required to assume these obligations, it could have a material adverse effect on our financial condition, results of operations or cash flows.

There remain potential federal income tax liabilities related to the acquisition of El Paso Tennessee Pipeline Co.

In connection with our acquisition of El Paso Tennessee and the distributions made by El Paso Tennessee prior to its acquisition, the IRS issued a private letter ruling to old Tenneco Inc. (now known as El Paso Tennessee), in which it ruled that for United States federal income tax purposes the distributions would be tax-free to old Tenneco Inc. and, except to the extent cash was received in lieu of fractional shares, to its then existing stockholders; the merger would constitute a tax-free reorganization; and that other transactions effected in connection with the merger and distribution would be tax-free. If the distributions were not to qualify as tax-free, then a corporate level federal income tax would be assessed to the consolidated group of which old Tenneco Inc. was the common parent. This corporate level federal income tax would be payable by El Paso Tennessee. Under limited circumstances, however, new Tenneco Inc. and Newport News Shipbuilding Inc. have agreed to indemnify El Paso Tennessee for a defined portion of such tax liabilities.

We are subject to financing and interest rate exposure risks.

Our business and operating results can be harmed by factors such as the availability or cost of capital, changes in interest rates, changes in the tax rates due to new tax laws, changes in the structured finance market, market perceptions of us or the natural gas and energy industry, or our credit ratings.

We are subject to foreign currency exchange risk.

Fluctuations in the value of the dollar as it rises and falls daily on foreign currency exchanges can have a negative effect on our businesses and operating results.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

We utilize derivative financial instruments to manage market risks associated with energy commodities and interest and foreign currency exchange rates. Our market risks are monitored by our corporate risk management committee that operates independently from our business segments that create or actively manage these risk exposures to ensure compliance with our overall stated risk management policies as approved by our Board of Directors.

Trading Commodity Price Risk

Our Merchant Energy segment is exposed to market risks inherent in the financial instruments it uses for trading energy and energy related commodities. Merchant Energy records its energy trading activities, including transportation capacity and storage at fair value. Changes in fair value are reflected in our income statement. Merchant Energy's policy is to manage commodity price risks through a variety of financial instruments, including:

- exchange-traded futures contracts involving cash settlements;
- forward contracts involving cash settlements or physical delivery of an energy commodity;
- swap contracts which require payment to (or receipts from) counterparties based on the difference between fixed and variable prices for the commodity;
- exchange-traded and over-the-counter options; and
- other contractual arrangements.

Merchant Energy manages its market risk, subject to parameters established by our corporate risk management committee. Comprehensive risk management processes, policies, and procedures have been established to monitor and control its market risk. Our risk management committee also continually reviews these policies to ensure they are responsive to changing business conditions.

Merchant Energy measures the risk in its commodity and energy related contracts on a daily basis utilizing a Value-at-Risk model to determine the maximum potential one-day unfavorable impact on its earnings, due to normal market movements, and monitors its risk in comparison to established thresholds. The Value-at-Risk computations capture a significant portion of the exposure related to option positions, and utilize historical price movements over a specified period to project future price movements in the energy markets. Merchant Energy also utilizes other measures to provide additional assurance that the risks in its commodity and energy related contracts are being properly monitored on a daily basis, including sensitivity analysis, position limit control and credit risk management.

Based on a confidence level of 95 percent and a one-day holding period, Merchant Energy's estimated potential one-day unfavorable impact on income before income taxes and minority interest, as measured by Value-at-Risk, related to contracts held for trading purposes was approximately \$19 million, \$3 million and \$3 million at December 31, 2000, 1999, and 1998. The increase in Value-at-Risk during 2000 reflects the significant increase in our commodity trading activities during the period. In 2000, Merchant Energy's highest, lowest, and average estimated potential one day unfavorable impact on income before taxes and minority interest, as measured by Value-at-Risk were \$19 million, \$2 million and \$9 million. In the fourth quarter of 2000, Merchant Energy also began managing asset based commodity transactions under the same Value-at-Risk methodology utilized for trading purposes. The potential one-day unfavorable impact on income before income taxes and minority interest related to these asset based commodity transactions as measured by Value-at-Risk was \$10 million at December 31, 2000. In 2000, the highest, lowest and average estimated one-day unfavorable impact on income before income taxes and minority interest for the asset based commodity transactions, as measured by Value-at-Risk, were \$10 million, \$5 million, and \$8 million. The average value represents the average of the 2000 month end values. The high and low valuations represent the highest and lowest month end values during 2000. Actual losses could exceed those measured by Value-at-Risk.

Non-trading Commodity Price Risk

We mitigate market risk associated with significant physical transactions, including natural gas, crude oil and natural gas liquids production through the use of non-trading financial instruments, including forward contracts and swaps. Merchant Energy hedges a portion of the commodity risk for Production and Field Services by facilitating derivative financial instruments with third parties.

The estimated potential one-day unfavorable impact on income before income taxes and minority interest, as measured by Value-at-Risk, related to our non-trading commodity activities was insignificant at December 31, 2000, 1999, and 1998.

Interest Rate Risk

Many of our debt related financial instruments and project financing arrangements are sensitive to market fluctuations in interest rates. We mitigate exposure to interest rate risk through the use of non-trading derivative financial instruments, including interest rate and equity swaps.

In August 1999, we entered an interest rate swap agreement on a notional amount of $600 million with a termination date of July 2001. We swapped the fixed interest rate on our $600 million aggregate principal Senior Notes due 2001 for a floating 3 month LIBOR plus 0.1475 percent rate. We accounted for this transaction using accrual accounting. In November 2000, we terminated the swap. The termination of this swap did not materially impact our financial statements.

In March 1997, we purchased a 10.5 percent interest in CAPSA for approximately $57 million and entered into an equity swap for an additional 18.5 percent ownership. Under the equity swap, we paid interest to a counterparty, on a quarterly basis, on a notional amount of $100 million at a rate of LIBOR plus 0.85 percent. In exchange, we received 18.5 percent of CAPSA's dividends. In February 1999, we extended the term of the swap and modified the notional amount to $103 million at a rate of LIBOR plus 1.75 percent. In May 2000, we exercised our right to terminate the swap and purchased the counterparty's 18.5 percent ownership interest in CAPSA for approximately $127 million. During the term of this swap, we reflected changes in the market value of the equity swap in our income statement. The termination of the swap did not materially impact our financial statements.

The table below shows cash flows and related weighted average interest rates of our interest bearing securities, by expected maturity dates. As of December 31, 2000, the carrying amounts of short-term borrowings are representative of fair values because of the short-term maturity of these instruments. The fair value of the long-term debt has been estimated based on quoted market prices for the same or similar issues.

	December 31, 2000								December 31, 1999	
	Expected Fiscal Year of Maturity of Carrying Amounts									
	2001	2002	2003	2004	2005	Thereafter	Total	Fair Value	Carrying Amounts	Fair Value
	(Dollars in millions)									
Liabilities:										
Short-term debt — variable rate	$1,426						$1,426	$1,426	$1,251	$1,251
Average interest rate	5.6%									
Long-term debt, including current portion — fixed rate	$1,032	$522	$240	$ 71	$291	$4,482	$6,638	$6,722	$5,315	$5,204
Average interest rate	7.7%	8.4%	7.4%	9.8%	7.6%	7.6%				
Notes payable to unconsolidated affiliates — fixed rate	$ 84	$ 90	$ 51	$ 10	$ 12	$ 6	$ 253	$ 276		
Average interest rate	7.4%	7.4%	7.4%	7.4%	7.4%	7.4%				
Notes payable to unconsolidated affiliates — variable rate	$ 313					$ 174	$ 487	$ 487		
Average interest rate	7.3%					10.9%				
Company-obligated preferred securities:										
El Paso Energy Capital Trust I						$ 325	$ 325	$ 579	$ 325	$ 327
Average interest rate						4.8%				
El Paso Energy Capital Trust IV			$300				$ 300	$ 300		
Average interest rate			6.2%							

Foreign Currency Exchange Rate Risk

We manage our exposure to changes in foreign currency exchange rates by entering into derivative financial instruments, principally foreign currency forward purchase and sale contracts. Our primary exposure relates to changes in foreign currency rates on certain of our merchant activities outside the U.S. not denominated or adjusted to U.S. dollars. The following table summarizes the notional amounts, average settlement rates, and fair value for foreign currency forward purchase and sale contracts as of December 31, 2000:

		Notional Amount in Foreign Currency (in millions)	Average Settlement Rates	Fair Value in U.S. Dollars (in millions)
Canadian Dollars	Purchase	1,095	0.673	$(3)
	Sell	441	0.686	6
				$ 3

The following table summarizes foreign currency forward purchase and sale contracts by expected maturity dates along with annual anticipated cash flow impacts as of December 31, 2000:

		Expected Maturity Dates						
		2001	2002	2003	2004	2005	Thereafter	Total
		(in millions)						
Canadian Dollars	Purchase	$(1)	$(2)	$(1)	$—	$—	$ 1	$(3)
	Sell	3	2	1	—	—	—	6
	Net cash flow effect	$ 2	$—	$—	$—	$—	$ 1	$ 3

Equity Risk

Through Merchant Energy's financial services unit, we manage and invest in private investment funds as well as privately placed securities of both privately and publicly held companies. We account for these investments using investment company accounting. As a result, these holdings are measured at their fair value with changes in fair value recorded in our income statement. The fair value of these investments are determined based on estimates of amounts that would be realized if these securities were sold. Below are the fair values of our investments subject to equity risks at December 31, 2000 and 1999, as well as the impact of a ten percent increase or decrease in the fair values of those investments for each period presented:

	2000			1999		
	Fair Value	Impact of 10 Percent Increase	Impact of 10 Percent Decrease	Fair Value	Impact of 10 Percent Increase	Impact of 10 Percent Decrease
	(in millions)					
Investment funds	$ 7	$ 1	$(1)	$ 4	$—	$—
Securities	54	5	(5)	7	1	(1)
Other	1	—	—	1	—	—
Total	$62	$ 6	$(6)	$12	$ 1	$(1)

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

EL PASO CORPORATION

CONSOLIDATED STATEMENTS OF INCOME
(In millions, except per common share amounts)

	Year Ended December 31,		
	2000	1999	1998
Operating revenues			
Transportation	$ 1,420	$ 1,564	$ 1,530
Energy commodities	19,696	8,582	7,744
Gathering and processing	476	324	141
Other	358	239	145
	21,950	10,709	9,560
Operating expenses			
Cost of natural gas and other products	18,882	8,245	7,027
Operation and maintenance	913	835	956
Merger-related costs and asset impairment charges	91	557	15
Ceiling test charges	—	352	1,035
Depreciation, depletion, and amortization	589	608	624
Taxes, other than income taxes	144	145	138
	20,619	10,742	9,795
Operating income (loss)	1,331	(33)	(235)
Other income			
Earnings from unconsolidated affiliates	127	95	73
Other, net	92	129	110
	219	224	183
Income (loss) before interest, income taxes, and other charges	1,550	191	(52)
Interest and debt expense	538	453	387
Minority interest	144	61	37
Income tax expense (benefit)	286	(81)	(170)
	968	433	254
Income (loss) before extraordinary items and cumulative effect of accounting change	582	(242)	(306)
Extraordinary items, net of income taxes	70	—	—
Cumulative effect of accounting change, net of income taxes	—	(13)	—
Net income (loss)	$ 652	$ (255)	$ (306)
Basic earnings (loss) per common share			
Income (loss) before extraordinary items and cumulative effect of accounting change	$ 2.53	$ (1.06)	$ (1.35)
Extraordinary items, net of income taxes	0.30	—	—
Cumulative effect of accounting change, net of income taxes	—	(0.06)	—
Net income (loss)	$ 2.83	$ (1.12)	$ (1.35)
Diluted earnings (loss) per common share			
Income (loss) before extraordinary items and cumulative effect of accounting change	$ 2.44	$ (1.06)	$ (1.35)
Extraordinary items, net of income taxes	0.29	—	—
Cumulative effect of accounting change, net of income taxes	—	(0.06)	—
Net income (loss)	$ 2.73	$ (1.12)	$ (1.35)
Basic average common shares outstanding	230	228	226
Diluted average common shares outstanding	243	228	226

See accompanying notes.

EL PASO CORPORATION

CONSOLIDATED BALANCE SHEETS
(In millions, except common share amounts)

	December 31, 2000	December 31, 1999
ASSETS		
Current assets		
Cash and cash equivalents	$ 688	$ 545
Accounts and notes receivable, net of allowance of $111 in 2000 and $33 in 1999		
Customer	3,639	986
Unconsolidated affiliates	270	366
Other	422	310
Inventory	167	74
Assets from price risk management activities	4,281	233
Other	609	400
Total current assets	10,076	2,914
Property, plant, and equipment, net	11,659	10,265
Investments in unconsolidated affiliates	2,858	2,177
Assets from price risk management activities	1,638	413
Other	1,214	898
Total assets	$27,445	$16,667
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities		
Accounts and notes payable		
Trade	$ 3,339	$ 994
Unconsolidated affiliates	397	122
Other	416	542
Short-term borrowings (including current maturities of long-term debt)	2,458	1,343
Liabilities from price risk management activities	2,881	197
Current deferred credits	527	143
Other	449	362
Total current liabilities	10,467	3,703
Debt		
Long-term debt, less current maturities	5,606	5,223
Noncurrent notes payable to unconsolidated affiliates	343	—
	5,949	5,223
Deferred credits and other		
Liabilities from price risk management activities	898	95
Deferred income taxes	2,149	1,737
Noncurrent deferred credits	771	730
Other	686	539
	4,504	3,101
Commitments and contingencies		
Securities of subsidiaries		
Company-obligated preferred securities of consolidated trusts	625	325
Minority interests	2,331	1,368
	2,956	1,693
Stockholders' equity		
Common stock, par value $3 per share; authorized 750,000,000 shares; issued 243,318,833 shares in 2000 and 238,542,335 shares in 1999	730	716
Additional paid-in capital	1,619	1,367
Retained earnings	1,670	1,207
Accumulated other comprehensive income	(57)	(29)
Treasury stock (at cost) 8,538,358 shares in 2000 and 8,947,565 shares in 1999	(268)	(273)
Unamortized compensation	(125)	(41)
Total stockholders' equity	3,569	2,947
Total liabilities and stockholders' equity	$27,445	$16,667

See accompanying notes.

EL PASO CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS
(In millions)

	Year Ended December 31,		
	2000	1999	1998
Cash flows from operating activities			
Net income (loss)	$ 652	$ (255)	$ (306)
Adjustments to reconcile net income (loss) to net cash from operating activities			
Depreciation, depletion, and amortization	589	608	624
Deferred income tax expense (benefit)	328	(44)	(194)
Extraordinary items	(120)	—	—
Undistributed earnings in equity investees	(68)	(52)	(60)
Ceiling test charges	—	352	1,035
Non-cash portion of merger-related costs and asset impairment charges	11	380	—
Other	(51)	(35)	(40)
Working capital changes, net of non-cash transactions			
Accounts and notes receivable	(2,555)	(271)	481
Inventory	(10)	4	15
Change in price risk management activities, net	(1,787)	(204)	(40)
Accounts payable	1,960	132	(391)
Other working capital changes	100	(101)	39
Other	(89)	(13)	(130)
Net cash provided by (used in) operating activities	(1,040)	501	1,033
Cash flows from investing activities			
Purchases of property, plant, and equipment	(1,336)	(1,086)	(1,137)
Additions to investments	(1,387)	(832)	(689)
Cash paid for acquisitions, net of cash received	(524)	(165)	(373)
Net proceeds from the sale of assets	728	33	389
Proceeds from sale of investments	295	112	163
Change in cash deposited in escrow related to an equity investee	24	(101)	—
Repayment (advances) of notes receivable from unconsolidated affiliates	647	(262)	—
Net cash used in investing activities	(1,553)	(2,301)	(1,647)
Cash flows from financing activities			
Net borrowings (repayments) of commercial paper and short-term notes	(256)	156	288
Revolving credit borrowings	1,145	878	810
Revolving credit repayments	(715)	(1,253)	(1,017)
Payments to retire long-term debt	(127)	(343)	(289)
Net proceeds from the issuance of long-term debt	897	1,781	691
Net proceeds from issuance of Company-obligated preferred securities	293	—	317
Issuances (repurchases) of common stock	110	24	(20)
Dividends paid	(189)	(184)	(209)
Increase in notes payable to unconsolidated affiliates	583	222	—
Net proceeds from issuance of minority interests in subsidiaries	995	960	—
Other	—	—	2
Net cash provided by financing activities	2,736	2,241	573
Increase (decrease) in cash and cash equivalents	143	441	(41)
Cash and cash equivalents			
Beginning of period	545	104	145
End of period	$ 688	$ 545	$ 104

See accompanying notes.

EL PASO CORPORATION

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
(In millions, except per common share amounts)

	For the Years Ended December 31,					
	2000		1999		1998	
	Shares	Amount	Shares	Amount	Shares	Amount
Common stock, $3.00 par:						
Balance at beginning of year	239	$ 716	236	$ 707	234	$ 702
Issuance of common stock, net of related costs	1	3	1	3	—	1
Compensation related issuances	3	11	3	9	2	4
Retirement of Sonat treasury shares			(1)	(3)		
Balance at end of year	243	730	239	716	236	707
Additional paid-in capital:						
Balance at beginning of year		1,367		1,288		1,229
Issuance of common stock, net of related costs		37		30		8
Compensation related issuances		177		90		30
Tax benefit of equity plans		42		13		10
Retirement of Sonat treasury shares				(61)		
Other		(4)		7		11
Balance at end of year		1,619		1,367		1,288
Retained earnings:						
Balance at beginning of year		1,207		1,669		2,186
Net income (loss)		652		(255)		(306)
Dividends ($0.824, $0.800, and $0.765 per share)		(189)		(207)		(211)
Balance at end of year		1,670		1,207		1,669
Accumulated other comprehensive income:						
Balance at beginning of year		(29)		(12)		(4)
Cumulative translation adjustment		(30)		(12)		(7)
Other		2		(5)		(1)
Balance at end of year		(57)		(29)		(12)
Treasury stock, at cost:						
Balance at beginning of year	(9)	(273)	(5)	(150)	(4)	(112)
Issuance of treasury stock, net of related cost	—	2				
Stock repurchases					(1)	(37)
Compensation related issuances	—	3	(5)	(182)	—	(1)
Retirement of Sonat treasury shares			1	59		
Balance at end of year	(9)	(268)	(9)	(273)	(5)	(150)
Unamortized compensation:						
Balance at beginning of year		(41)		(65)		(81)
Restricted stock activity, net		(84)		(43)		16
Early vesting of equity plans				67		
Balance at end of year		(125)		(41)		(65)
Total stockholders' equity	234	$3,569	230	$2,947	231	$3,437
Comprehensive income (loss)		$ 624		$ (272)		$ (314)

See accompanying notes.

1. Summary of Significant Accounting Policies

Basis of Presentation and Principles of Consolidation

Our consolidated financial statements include the accounts of all majority-owned, controlled subsidiaries after the elimination of all significant intercompany accounts and transactions. We account for investments in companies where we have the ability to exert significant influence, but not control, over operating and financial policies using the equity method. Our consolidated financial statements for previous periods include reclassifications that were made to conform to the current year presentation. Those reclassifications have no impact on reported net income or stockholders' equity.

Use of Estimates

The preparation of financial statements in conformity with generally accepted accounting principles requires us to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues, and expenses and disclosure of contingent assets and liabilities that exist at the date of the financial statements. Our actual results are likely to differ from those estimates.

Accounting for Regulated Operations

Our interstate natural gas systems are subject to the jurisdiction of FERC in accordance with the Natural Gas Act of 1938 and the Natural Gas Policy Act of 1978. Each system operates under separate FERC approved tariffs which establish rates, terms and conditions under which each system provides services to its customers. Our businesses that are subject to the regulations and accounting requirements of FERC have followed the accounting requirements of Statement of Financial Accounting Standards (SFAS) No. 71, *Accounting for the Effects of Certain Types of Regulation*, which may differ from the accounting requirements of our non-regulated entities. Transactions that have been recorded differently as a result of regulatory accounting requirements include the capitalization of an equity return component on regulated capital projects, employee related benefits, and other costs and taxes included in, or expected to be included in, future rates, including costs to refinance debt.

When the accounting method followed is required by or allowed by the regulatory authority for rate-making purposes, the method conforms to the generally accepted accounting principle of matching costs with the revenues to which they apply.

Cash and Cash Equivalents

We consider short-term investments purchased with an original maturity of less than three months to be cash equivalents.

Inventory

Our inventory consists of materials and supplies, natural gas in storage for non-trading purposes, and optic fiber being constructed for sale to, or exchange with, third parties. We value these inventories at the lower of cost or market with cost determined using the average cost method.

Property, Plant, and Equipment

Regulated. Our regulated property, plant, and equipment is recorded at its original cost of construction or, upon acquisition, the cost to the entity that first placed the asset in service. We capitalize direct costs, like labor and materials, and indirect costs, like overhead and allowance for funds used during construction. We capitalize the major units of property replacements or improvements and expense the minor ones.

When applicable, we use the composite (group) method to depreciate regulated property, plant, and equipment. Assets with similar lives and other characteristics are grouped and depreciated as one asset. We apply the depreciation rate, approved in our rates, to the total cost of the group, until its net book value equals its salvage value. Currently, our depreciation rates vary from 1 to 33 percent. These rates depreciate the related assets over 2 to 36 years. We re-evaluate depreciation rates each time we redevelop our transportation rates.

When we retire regulated property, plant, and equipment, we charge accumulated depreciation and amortization for the original cost, plus the cost of retirement (the cost to remove, sell, or dispose), less its salvage value. We do not recognize a gain or loss unless we sell an entire operating unit. We include gains or losses on dispositions of operating units in income.

Non-Regulated. We record our non-regulated property, plant, and equipment at its original cost of construction or, upon acquisition, at the fair value of the assets acquired. We capitalize all direct and indirect costs of the project, including interest costs on related debt.

We depreciate these properties over their estimated useful lives using a straight line or composite method. The annual depreciation rates are as follows:

Gathering and processing systems	2.5% to 20.0%
Power facilities	2.0% to 33.0%
Transportation equipment	2.5% to 10.0%
Buildings and improvements	2.5% to 20.0%
Office and miscellaneous equipment	10.0% to 33.0%

When we retire non-regulated properties, we reduce property, plant, and equipment for its original cost, less accumulated depreciation, and salvage. Any remaining amount is charged to income.

General. At December 31, 2000 and 1999, we had approximately $875 million and $597 million construction work in progress included in our property, plant, and equipment.

We evaluate impairment of our regulated and non-regulated property, plant, and equipment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable in accordance with SFAS No. 121, *Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to be Disposed Of.*

Natural Gas and Oil Properties

We use the full cost method to account for our natural gas and oil properties. Under the full cost method, all productive and nonproductive costs incurred in connection with the acquisition, exploration, and development of natural gas and oil reserves are capitalized. These capitalized costs include the costs of all unproved properties, internal costs directly related to acquisition and exploration activities, and capitalized interest.

We amortize these costs using a unit of production method over the life of our proved reserves. We exclude unevaluated properties from our amortization base, until we make a determination as to the existence of proved reserves. Our total capitalized costs are limited to a ceiling of the present value of future net revenues, discounted at 10 percent, plus the lower of cost or fair market value of unproved properties. If these discounted revenues are not equal to or greater than total capitalized costs, we are required to write-down our capitalized costs to this level. In 1999 and 1998, we determined that capitalized costs exceeded the ceiling test limits by a total of $352 million and $1,035 million. These write-downs are included in our income statement as ceiling test charges.

We treat the sale of natural gas and oil properties as an adjustment to cost of these properties. We do not recognize a gain or loss on these sales, unless the properties sold is significant.

Intangible Assets

Intangible assets consist primarily of goodwill arising as a result of mergers and acquisitions. We amortize these intangible assets using the straight-line method over periods ranging from 5 to 40 years. Our accumulated amortization of intangible assets was $101 million and $62 million as of December 31, 2000 and 1999. We evaluate impairment of goodwill in accordance with SFAS No. 121. Under this methodology, when an event occurs to suggest that impairment may have occurred, we evaluate the undiscounted net cash flows of the underlying asset or entity. If these cash flows are not sufficient to recover the value of the underlying asset or entity plus the goodwill amount, these cash flows are discounted at a risk-adjusted rate with any difference recorded as a charge to our income statement.

Revenue Recognition

Our regulated businesses recognize revenues from natural gas transportation in the period the service is provided. Reserves are provided on revenues collected that may be subject to refund. Revenues on services other than transportation are recorded when they are earned.

Our non-regulated businesses record revenues at various points when they are earned, including when deliveries of the physical commodities are made, or in the period services are provided. See the discussion of price risk management activities below for our revenue recognition policies on our trading activities.

In the fourth quarter of 2000, we implemented Emerging Issues Task Force Issue No. 99-19, *Reporting Revenue Gross as a Principal versus Net as an Agent*, which provides guidance on the gross versus net presentation of revenues and expenses. As a result of adoption, revenues and related costs increased by $87 million, $128 million, and $60 million for 2000, 1999, and 1998. These reclassifications had no impact on net income or earnings per share.

Environmental Costs

Expenditures for ongoing compliance with environmental regulations that relate to current operations are expensed or capitalized as appropriate. We expense amounts that relate to existing conditions caused by past operations, and which do not contribute to current or future revenue generation. We record liabilities when environmental assessments indicate that remediation efforts are probable and the costs can be reasonably estimated. Estimates of our liabilities are based upon currently available facts, existing technology and presently enacted laws and regulations taking into consideration the likely effects of inflation and other societal and economic factors, and include estimates of associated legal costs. These amounts also consider prior experience in remediating contaminated sites, other companies' clean-up experience and data released by the EPA or other organizations. They are subject to revision in future periods based on actual costs or new circumstances, and are included in our balance sheet at their undiscounted amounts. We evaluate recoveries separately from the liability and, when recovery is assured, we record and report an asset separately from the associated liability in our financial statements.

Price Risk Management Activities

We utilize derivative financial instruments to manage market risks associated with commodities we sell, interest rates, and foreign currency exchange rates. We engage in both trading and non-trading commodity price risk management activities.

Our trading activities consist of services provided to the energy sector, primarily related to natural gas and power. Our energy trading activities, including transportation capacity and storage, are accounted for using the mark-to-market method of accounting. We conduct our trading activities through a variety of financial instruments, including:

- exchange traded futures contracts involving cash settlement;
- forward contracts involving cash settlement or physical delivery of an energy commodity;
- swap contracts, which require us to make payments to (or receive payments from) counterparties based on the difference between fixed and variable prices for the commodity;
- exchange-traded and over-the-counter options; and
- other contractual arrangements.

Under the mark-to-market method of accounting, commodity and energy related contracts are reflected at quoted or estimated market value with resulting gains and losses included in our income statement. Net gains or losses recognized in a period result primarily from the impact of price movements on transactions originating in that or previous periods. Assets and liabilities resulting from mark-to-market accounting are included in our balance sheets and are classified according to their term to maturity. We reflect receivables and payables that arise upon the actual settlement of these contracts separately from price risk management activities in our balance sheet as trade receivables or payables. Cash inflows and outflows associated with these price risk management activities are recognized in operating cash flows as transactions are settled. During the years ended December 31, 2000 and 1999, we recognized gross margins from our trading activities of $406 million and $91 million.

The market value of commodity and energy related contracts reflects our best estimate, and considers factors including closing exchange and over-the-counter quotations, time value, and volatility factors underlying these contracts. The values are adjusted to reflect the potential impact of liquidating our position in an orderly manner over a reasonable period of time under present market conditions and to reflect other types of risks, including model risk, credit risk and operational risks. In the absence of quoted market prices, we utilize other valuation techniques to estimate fair value. The use of these techniques requires us to make estimations of future prices and other variables, including market volatility, price correlation, and market liquidity. Changes in these estimates could have a significant impact on our market valuations and could materially impact our estimates.

Derivative and other financial instruments are also utilized in connection with non-trading activities. We enter into forwards, swaps, and other contracts to hedge the impact of market fluctuations on assets, liabilities, or other contractual commitments. Hedge accounting is applied only if the derivative reduces the risk of the underlying hedged item, is designated as a hedge at its inception, and is expected to result in financial impacts which are inversely correlated to those of the item being hedged. If correlation ceases to exist, hedge accounting is terminated and mark-to-market accounting is applied. Changes in the market value of hedged transactions are deferred until the gain or loss on the hedged item is recognized. Derivatives held for non-trading purposes are recorded as gains or losses in operating income and cash inflows and outflows are recognized in operating cash flows as transactions are settled. See Note 6 for a further discussion of our price risk management activities.

Income Taxes

We report income taxes based on income reported on our tax returns along with a provision for deferred income taxes. Deferred income taxes reflect the estimated future tax consequences of differences between the financial statement and tax bases of assets and liabilities and carryovers at each year end. We account for tax credits under the flow-through method, which reduces the provision for income taxes in the year the tax credits first become available. We reduce deferred tax assets by a valuation allowance when, based upon our estimates, it is more likely than not that a portion of those assets will not be realized in a future period. The estimates utilized in the recognition of deferred tax assets are subject to revision in future periods based on new facts or circumstances.

Comprehensive Income (Loss)

Comprehensive income (loss) is determined based on net income (loss), adjusted for changes in accumulated other comprehensive income.

Treasury Stock

We account for treasury stock using the cost method and report it in our balance sheet as a reduction to stockholders' equity. Treasury stock sold or issued is valued on a first-in, first-out basis. Included in treasury stock at December 31, 2000, and 1999, were 1.36 million shares of common stock that were reserved for use under several of our benefit plans, as well as approximately 5.8 million shares of common stock which were held in a trust under our deferred compensation programs.

Stock-Based Compensation

We apply the provisions of Accounting Principles Board Opinion No. 25 and its related interpretations in accounting for our stock compensation plans. Accordingly, compensation expense is not recognized for stock options unless the options were granted at an exercise price lower than market on the grant date. We use fixed and variable plan accounting for our fixed and variable compensation plans.

Cumulative Effect of Accounting Change

In April 1998, the American Institute of Certified Public Accountants issued Statement of Position 98-5, *Reporting on the Costs of Start-Up Activities.* The statement defined start-up activities and required start-up and organization costs be expensed as incurred. In addition, it required that any such cost that existed on the balance sheet be expensed upon adoption of the pronouncement. We adopted the pronouncement effective January 1, 1999, and reported a charge of $13 million, net of income taxes, as a cumulative effect of an accounting change.

Accounting for Derivative Instruments and Hedging Activities

In June of 1998, the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standards (SFAS) No. 133, *Accounting for Derivative Instruments and Hedging Activities.* In June of 1999, the FASB extended the adoption date of SFAS No. 133 through the issuance of SFAS No. 137, *Deferral of the Effective Date of SFAS 133.* In June 2000, the FASB issued SFAS No. 138, *Accounting for Certain Derivative Instruments and Certain Hedging Activities*, which also amended SFAS No. 133. SFAS No. 133, and its amendments and interpretations, establishes accounting and reporting standards for derivative instruments, including derivative instruments embedded in other contracts, and derivative instruments used for hedging activities. It requires that we measure all derivative instruments at their fair value, and classify them as either assets or liabilities on our balance sheet, with a corresponding offset to income or other comprehensive income depending on their designation, their intended use, or their ability to qualify as hedges under the standard.

We adopted SFAS No. 133 on January 1, 2001, and applied the standard to all derivative instruments that existed on that date, except for derivative instruments embedded in other contracts. As provided for in SFAS No. 133, we applied the provisions of the standard to derivative instruments embedded in other contracts issued, acquired, or substantially modified after December 31, 1998.

We use a variety of derivative instruments to conduct both energy trading activities and to hedge risks associated with commodity prices, foreign currencies and interest rates. The derivative instruments we use in commodity trading activities are recorded at their fair value in our financial statements under the provisions of Emerging Issues Task Force Issue No. 98-10, *Accounting for Contracts Involved in Energy Trading and Risk Management Activities.* As a result, SFAS No. 133 did not impact our accounting for these instruments.

Based on commodity prices, interest rates, and foreign currency exchange rates existing at December 31, 2000, we will reflect the impact of our adoption of SFAS No. 133 as of January 1, 2001, by recording a cumulative effect transition adjustment as a charge to other comprehensive income of

$821 million, net of income taxes, a reduction of assets of $37 million, and an increase in liabilities of $784 million. This represents the fair value of our derivative instruments designated as cash flow hedges. The majority of the initial charge relates to the hedging of forecasted sales of natural gas we expect to produce through the end of 2001.

Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities

In September 2000, the FASB issued SFAS No. 140, *Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities*, which replaces SFAS No. 125. This statement revises the standards for accounting for securitizations and other transfers of financial assets and collateral and requires certain disclosures, but carries over most of SFAS No. 125's provisions without reconsideration. This standard has various effective dates, the earliest of which is for fiscal years ending after December 15, 2000. This pronouncement will not have a material effect on our financial statements.

2. Mergers and Acquisitions

Coastal

In January 2001, we merged with Coastal. We accounted for the transaction as a pooling of interests and converted each share of Coastal common stock and Class A common stock on a tax-free basis into 1.23 shares of our common stock. We exchanged Coastal's outstanding convertible preferred stock for our common stock on the same basis as if the preferred stock had been converted into Coastal common stock immediately prior to the merger. The total value of the transaction was approximately $24 billion, including $7 billion of assumed debt and preferred equity. In the merger, we issued approximately 271 million shares of our common stock, including 4 million shares in exchange for Coastal stock options.

Coastal is a diversified energy holding company. It is engaged, through its subsidiaries and joint ventures, in natural gas transmission, storage, gathering, processing and marketing; natural gas and oil exploration and production; petroleum refining, marketing and distribution; chemicals production; power production; and coal mining. Coastal owns interests in approximately 18,000 miles of natural gas pipelines extending across the midwestern and the Rocky Mountain areas of the United States and has proved reserves of 3.6 Tcfe. Coastal also has international and domestic interests in natural gas and oil producing properties, power production plants, and crude oil refining facilities.

Presented below are the unaudited pro forma results of this merger as if it had occurred on January 1, 1998:

	Year ended December 31,		
	2000	1999	1998
	(In millions, except per share amounts)		
Operating Results Data:			
Operating revenues[1]	$49,268	$27,332	$23,773
Income from continuing operations	1,236	257	176
Basic earnings per common share from continuing operations available to common stockholders	2.50	0.52	0.35
Diluted earnings per common share from continuing operations available to common stockholders	2.43	0.52	0.34
Basic average common shares outstanding	494	490	487
Diluted average common shares outstanding	513	497	495

(1) Operating revenues include an adjustment to conform the presentation of Coastal's petroleum trading activities to our manner of presentation.

Texas Midstream Operations

In December 2000, we completed our purchase of PG&E's Texas Midstream operations. The total value of the transaction was $887 million, including assumed debt of approximately $527 million. The transaction was accounted for as a purchase and is included in our Field Services segment.

The operations acquired consisted of 7,500 miles of intrastate natural gas transmission and natural gas liquids pipelines that transport approximately 2.8 Bcf/d, nine natural gas processing and fractionation plants that currently process 1.5 Bcf/d, and rights to 7.2 Bcf of natural gas storage capacity. In March 2001, we sold some of these acquired natural gas liquids transportation and several fractionation assets to Energy Partners for approximately $133 million.

Sonat

In October 1999, we completed our merger with Sonat, a diversified energy holding company engaged in domestic oil and natural gas exploration and production, the transmission and storage of natural gas, and natural gas and power marketing. In the merger, one share of our common stock was issued in exchange for each share of Sonat common stock. Total common shares issued in the merger were approximately 110 million. The transaction was valued at approximately $7 billion based on our closing stock price on October 25, 1999. The merger was accounted for as a pooling of interests.

Divestitures

During 2000, we completed the sales of East Tennessee Natural Gas Company, Sea Robin Pipeline Company and our one-third interest in Destin Pipeline Company to comply with a Federal Trade Commission order related to our merger with Sonat. Proceeds from the sales were approximately $616 million and we recognized an extraordinary gain of $89 million, net of income taxes of $60 million. In December 2000, we sold our interest in Oasis Pipeline Company to comply with a Federal Trade Commission order. We incurred a loss on this transaction of approximately $19 million, net of income taxes. We recorded the gains and losses on these sales as extraordinary items in our income statement.

As a result of our merger with Coastal, we will be required by the Federal Trade Commission to sell our Midwestern system, a pipeline system in the midwest. Total estimated proceeds from the sale are $90 million, resulting in an estimated gain of $50 million, before income taxes. We expect to complete this sale in the second quarter of 2001.

Additionally, in the first quarter of 2001, Energy Partners sold its interests in several offshore assets. These sales consisted of interests in seven natural gas pipeline systems, a dehydration facility, and two offshore platforms. Proceeds from the sales of these assets were approximately $135 million and resulted in a loss to the partnership of approximately $23 million. As consideration for these sales, we committed to pay Energy Partners a series of payments totaling $29 million. This amount, as well as our proportional share of the losses on the sale of the partnership's assets, will be recorded as a charge in our income statement in the first quarter of 2001.

We do not anticipate the impact from these sales to be material to our ongoing financial position, operating results, or cash flows.

3. Merger-Related Costs and Asset Impairment Charges

Merger-Related Costs

During 2000, 1999, and 1998, we incurred merger-related charges related to our mergers with Coastal, Sonat, and our merger in 1998 with Zilkha Energy Company. These charges included the following:

	Year Ended December 31,		
	2000	1999	1998
	(In millions)		
Employee severance, retention and transition costs	$31	$303	$—
Transaction costs	44	62	—
Merger-related asset impairments	—	78	—
Other	5	72	15
	$80	$515	$15

Employee severance, retention and transition costs include direct payments to, and benefit costs for severed employees and early retirees that occurred as a result of merger-related workforce consolidations within our operating segments and the elimination of redundant positions within our merged operations. These costs included actual severance payments and costs for pension and post-retirement benefits settled and curtailed under existing benefit plans. Retention charges include payments to employees who were retained following the merger and payments to employees to satisfy contractual obligations. Transition costs relate to costs to relocate employees and costs for severed and retired employees arising after their severance date to transition their jobs into the ongoing workforce. The unpaid portion of these charges was $7 million at December 31, 2000, and $76 million at December 31, 1999.

Transaction costs include investment banking, legal, accounting, consulting and other advisory fees incurred to obtain federal and state regulatory approvals and take other actions necessary to complete our mergers.

Merger-related asset impairments relate to write-offs or write-downs of capitalized costs for duplicate systems, redundant facilities and assets whose value was impaired as a result of decisions on the strategic direction of our combined operations following each of our mergers.

Other costs primarily consist of charges to conform accounting policies and practices, integrate facilities, and retain seismic data in our production operations.

In conjunction with the Coastal merger, we issued approximately 4.4 million shares of common stock in exchange for Coastal options. This resulted in a charge of approximately $278 million that will be recorded in the first quarter of 2001. On January 30, we announced a workforce reduction and consolidation. The restructuring resulted in the reduction of 3,285 full-time positions through terminations and early retirement. A majority of the total charges connected with the restructuring will be recorded in the first quarter of 2001 and are estimated to be approximately $890 million.

Asset Impairment Charges

During 2000 and 1999, we incurred asset impairment charges of $11 million and $42 million. The 2000 charge resulted from Field Services' impairment of its Needle Mountain processing facility in Arizona due to unrecoverability of costs. The 1999 charges consisted of impairments of regulatory assets that were not recoverable based on the settlement of SNG's rate case.

4. Income Taxes

The following table reflects the components of income tax expense (benefit) included in income (loss) before extraordinary items and cumulative effect of accounting change for the three years ended December 31:

	2000	1999	1998
		(In millions)	
Current			
Federal	$(119)	$(44)	$ 25
State	(19)	(4)	(6)
Foreign	7	11	5
	(131)	(37)	24
Deferred			
Federal	377	(51)	(210)
State	43	8	17
Foreign	(3)	(1)	(1)
	417	(44)	(194)
Total income tax expense (benefit)	$ 286	$(81)	$(170)

Our tax expense (benefit), included in income (loss) before extraordinary items and cumulative effect of accounting change, differs from the amount computed by applying the statutory federal income tax rate of 35 percent for the following reasons at December 31:

	2000	1999	1998
		(In millions)	
Tax expense (benefit) at the statutory federal rate of 35%	$304	$(113)	$(167)
Increase (decrease)			
State income tax, net of federal income tax benefit	16	3	7
Dividend exclusion	(26)	(14)	(7)
Non-deductible portion of merger-related costs	11	29	—
Foreign income taxed at different rates, not subject to U.S. tax	(19)	(9)	(8)
Deferred credit on loss carryover	(18)	—	—
Preferred stock dividends of a subsidiary	9	9	9
Other	9	14	(4)
Income tax expense (benefit)	$286	$ (81)	$(170)
Effective tax rate	33%	25%	36%

The following are the components of our net deferred tax liability at December 31:

	2000	1999
	(In millions)	
Deferred tax liabilities		
Property, plant, and equipment	$2,657	$2,364
Investments in unconsolidated affiliates	272	91
Price risk management activities	244	17
Regulatory and other assets	657	469
Total deferred tax liability	3,830	2,941
Deferred tax assets		
U.S. net operating loss and tax credit carryovers	487	364
Accrual for regulatory issues	247	272
Employee benefit and deferred compensation obligations	197	211
Other liabilities	723	492
Valuation allowance	(3)	(6)
Total deferred tax asset	1,651	1,333
Net deferred tax liability	$2,179	$1,608

At December 31, 2000, the portion of the cumulative undistributed earnings of our foreign subsidiaries and foreign corporate joint ventures on which we have not recorded U.S. income taxes was approximately $178 million. Since these earnings have been or are intended to be indefinitely reinvested in foreign operations, no provision has been made for any U.S. taxes or foreign withholding taxes that may be applicable upon actual or deemed repatriation. If a distribution of such earnings were to be made, we might be subject to both foreign withholding taxes and U.S. income taxes, net of any allowable foreign tax credits or deductions. However, an estimate of these taxes is not practicable. For these same reasons, we have not recorded a provision for U.S. income taxes on the foreign currency translation adjustment recorded in other comprehensive income.

The tax benefit associated with the exercise of non-qualified stock options and the vesting of restricted stock as well as restricted stock dividends, reduced taxes payable by $42 million in 2000, $13 million in 1999 and $10 million in 1998. These benefits are included in additional paid-in capital in our balance sheets.

As of December 31, 2000, we had capital loss carryovers of $21 million for which the carryover period ends in 2001, alternative minimum tax credits of $71 million that carryover indefinitely, and $2 million of general business credit carryovers for which the carryover periods end at various times in the years 2006 through 2017. Usage of these carryovers is subject to the limitations provided under Sections 382 and 383 of the Internal Revenue Code as well as the separate return limitation year rules of IRS regulations. The table below presents the details of our net operating loss carryover periods.

	Carryover Period				
	2001	2002 - 2010	2011 - 2015	2016 - 2020	Total
			(In millions)		
Net operating loss	—	$74	$253	$835	$1,162

We recorded a valuation allowance to reflect the estimated amount of deferred tax assets which we may not realize due to the expiration of net operating loss and tax credit carryovers. As of December 31, 2000 and 1999, approximately $1 million and $4 million, respectively, of the valuation allowance relates to net operating loss carryovers of an acquired company. The remainder of the allowance relates to general business credit carryovers. With the exception of $2 million, any tax benefits subsequently recognized from the reversal of the allowance will be allocated to additional acquisition cost assigned to utility plant.

Prior to 1999, our subsidiary, El Paso Tennessee Pipeline Co., and its subsidiaries filed a separate consolidated federal income tax return from our consolidated return. On January 1, 1999, as a result of a 1998 tax-free internal reorganization, El Paso Tennessee and its subsidiaries joined our consolidated federal income tax group. The subsidiaries of Sonat Inc. joined our consolidated federal income tax group on October 26, 1999, after our merger. After the Coastal merger, we will file a consolidated federal income tax return with Coastal.

In connection with our acquisition of El Paso Tennessee, we entered into a tax sharing agreement with Newport News Shipbuilding Inc., new Tenneco Inc., and El Paso Tennessee. This tax sharing agreement provides, among other things, for the allocation among the parties of tax assets and liabilities arising prior to, as a result of and subsequent to the distributions of new Tenneco Inc. and Newport News Shipbuilding Inc. to the shareholders of old Tenneco Inc. (now known as El Paso Tennessee).

5. Earnings Per Share

We calculated basic and diluted earnings per share amounts as follows.

	2000		1999	1998
	Basic	Diluted	Basic[1]	Basic[1]
	(In millions, except per common share amounts)			
Income (loss) before extraordinary items and cumulative effect of accounting change	$ 582	$ 582	$ (242)	$ (306)
Interest on trust preferred securities	—	10	—	—
Adjusted income (loss) before extraordinary items and cumulative effect of accounting change	582	592	(242)	(306)
Extraordinary items, net of income taxes	70	70	—	—
Cumulative effect of accounting change, net of income taxes	—	—	(13)	—
Adjusted net income (loss)	$ 652	$ 662	$ (255)	$ (306)
Average common shares outstanding	230	230	228	226
Effect of diluted securities				
Stock options	—	5	—	—
Trust preferred securities	—	8	—	—
Average common shares outstanding	230	243	228	226
Earnings (loss) per common share				
Adjusted income (loss) before extraordinary items and cumulative effect of accounting change	$2.53	$2.44	$(1.06)	$(1.35)
Extraordinary items, net of income taxes	0.30	0.29	—	—
Cumulative effect of accounting change, net of income taxes	—	—	(0.06)	—
Adjusted net income (loss)	$2.83	$2.73	$(1.12)	$(1.35)

(1) The addition of potential average common shares outstanding for 1999 and 1998 is antidilutive and would have reduced the loss per share.

6. Financial Instruments and Price Risk Management Activities

Fair Value of Financial Instruments

The carrying amounts and estimated fair values of our financial instruments at December 31 are as follows:

	2000		1999	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(In millions)			
Balance sheet financial instruments:				
Long-term debt, including current maturities	$6,638	$ 6,722	$5,315	$5,204
Notes payable to unconsolidated affiliates	740	763	—	—
Company-obligated preferred securities of subsidiaries	625	879	325	327
Trading instruments				
Futures contracts	137	137	(24)	(24)
Option contracts[1]	(118)	(118)	264	264
Swap and forward contracts	1,153	1,153	(65)	(65)
Equity swap	—	—	10	10
Other financial instruments:				
Non-trading instruments				
Commodity swap and forward contracts	$ —	$(1,214)	$ —	$ (17)
Commodity futures contracts	—	—	—	2
Foreign currency forward purchases	—	3	—	4
Interest rate swap agreements	—	—	—	4

(1) Excludes transportation capacity, tolling agreements, and natural gas in storage held for trading purposes since these do not constitute financial instruments.

As of December 31, 2000, and 1999, our carrying amounts of cash and cash equivalents, short-term borrowings, and trade receivables and payables are representative of fair value because of the short-term nature of these instruments. The fair value of long-term debt with variable interest rates approximates its carrying value because of the market based nature of the debt's interest rates. We estimated the fair value of debt with fixed interest rates based on quoted market prices for the same or similar issues. We estimated the fair value of all derivative financial instruments based on quoted market prices, current market conditions, estimates we obtained from third-party brokers or dealers, or amounts derived using valuation models.

Trading Commodity Activities

The fair value of commodity and energy related contracts entered into for trading purposes as of December 31, 2000 and 1999, and the average fair value of those instruments are set forth below.

	Assets	Liabilities	Average Fair Value for the Year Ended December 31,(1)
		(In millions)	
2000			
Futures contracts	$ 137	$ —	$266
Option contracts	2,135	(1,594)	589
Swap and forward contracts	3,647	(2,185)	518
1999			
Futures contracts	$ 2	$ (26)	$(12)
Option contracts	455	(35)	184
Swap and forward contracts	189	(231)	93

(1) Computed using the net asset (liability) balance at each month end.

Notional Amounts and Terms

The notional amounts and terms of our energy commodity financial instruments at December 31, 2000, and 1999 are set forth below (natural gas volumes are in trillions of British thermal units, power volumes are in millions of megawatt hours, liquids volumes are in millions of barrels, weather volumes are in thousands of degree days, and energy capacity volumes are in millions of kilowatt hours):

	Fixed Price Payor	Fixed Price Receiver	Maximum Terms in Years
2000			
Energy Commodities:			
Natural gas	34,305	29,895	27
Power	133	143	20
Liquids(1)	8	8	6
Weather	133	135	—
Energy capacity	22	29	13
1999			
Energy Commodities:			
Natural gas	26,457	24,565	26
Power	30	41	20
Liquids(1)	8	8	7

(1) Liquids include crude oil, condensate and natural gas liquids.

The notional amount and terms of foreign currency forward purchases and sales at December 31, 2000 and 1999, were as follows:

	Notional Volume		Maximum
	Buy	Sell	Term in Years
2000			
Foreign Currency (in millions)			
Canadian Dollars	1,095	441	8
1999			
Foreign Currency (in millions)			
Canadian Dollars	296	194	9
British Pounds	—	28	9

Notional amounts reflect the volume of transactions but do not represent the actual amounts exchanged by the parties. As a result, notional amounts are an incomplete measure of our exposure to market or credit risks. The maximum terms in years detailed above are not indicative of likely future cash flows as these positions may be offset or cashed-out in the commodity and currency markets based on our risk management needs and liquidity in those markets.

The weighted average maturity of our entire portfolio of price risk management activities was approximately two years as of December 31, 2000, and six years as of December 31, 1999.

Market and Credit Risks

We serve a diverse customer group that generates a need for a variety of financial structures, products and terms. This diversity requires us to manage, on a portfolio basis, the resulting market risks inherent in these transactions subject to parameters established by our risk management committee. We monitor market risks through a risk control committee operating independently from the units that create or actively manage these risk exposures to ensure compliance with our stated risk management policies.

We measure and adjust the risk in our portfolio in accordance with mark-to-market and other risk management methodologies which utilize forward price curves in the energy markets to estimate the size and probability of future potential exposure.

Credit risk relates to the risk of loss that we would incur as a result of non-performance by counterparties pursuant to the terms of their contractual obligations. We maintain credit policies with regard to our counterparties to minimize overall credit risk. These policies require an evaluation of potential counterparties' financial condition (including credit rating), collateral requirements under certain circumstances (including cash in advance, letters of credit, and guarantees), and the use of standardized agreements that allow for the netting of positive and negative exposures associated with a single counterparty. The counterparties associated with our assets from price risk management activities are summarized as follows:

	Assets from Price Risk Management Activities as of December 31, 2000		
	Investment Grade(1)	Below Investment Grade	Total(2)
	(In millions)		
Energy marketers	$2,459	$ 8	$2,467
Financial institutions	1,161	—	1,161
Oil and natural gas producers	613	—	613
Natural gas and electric utilities	1,496	54	1,550
Industrials	98	2	100
Municipalities	17	—	17
Other	10	1	11
Total assets from price risk management activities	$5,854	$65	$5,919

	Assets from Price Risk Management Activities as of December 31, 1999		
	Investment Grade(1)	Below Investment Grade	Total(2)
	(In millions)		
Energy marketers	$226	$ 1	$227
Financial institutions	21	—	21
Oil and natural gas producers	26	—	26
Natural gas and electric utilities	251	2	253
Industrials	15	—	15
Municipalities	64	—	64
Other	40	—	40
Total assets from price risk management activities	$643	$ 3	$646

(1) Investment Grade is primarily determined using publicly available credit ratings along with consideration of collateral, which encompass standby letters of credit, parent company guarantees and property interest, including natural gas and oil reserves. Included in Investment Grade are counterparties with a minimum Standard & Poor's or Moody's rating of BBB− or Baa3, respectively, or minimum implied (through internal credit analysis) Standard & Poor's equivalent rating of BBB−.

(2) We had one customer in 2000 and four customers in 1999 that comprised greater than 5 percent of assets from price risk management activities. Each of these customers have investment grade ratings.

This concentration of counterparties may impact our 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. Based on our policies, risk exposure, and reserves, we do not anticipate a material adverse effect on our financial position, operating results, or cash flows as a result of counterparty nonperformance.

Non-Trading Price Risk Management Activities

We also utilize derivative financial instruments for non-trading activities to mitigate market price risk associated with significant physical transactions. Non-trading commodity activities are accounted for using hedge accounting provided they meet hedge accounting criteria. Non-trading activities are conducted through exchange traded futures contracts, swaps, and forward agreements with third parties.

At December 31, 2000 and 1999, the notional amounts and terms of contracts held for purposes other than trading were as follows:

	2000			1999		
	Notional Volume		Maximum	Notional Volume		Maximum
	Buy	Sell	Term in Years	Buy	Sell	Term in Years
Commodity						
Natural Gas (TBtu)	115	519	12	22	548	13
Power (MMWh)	64	35	2	—	—	—
Liquids (MMBbls)	—	2	1	—	1	2

In August 1999, we entered an interest rate swap agreement with a notional amount of $600 million and a termination date of July 2001. In the agreement, we swapped the fixed interest rate on our July 1999 $600 million aggregate principal Senior Notes due 2001, for a floating three month LIBOR plus a margin of 14.75 basis points. Total interest expense was less than $1 million in 2000 and 1999, as a result of this swap agreement. In November 2000, we terminated this swap. The termination of this swap did not have a material impact on our financial results.

In May 2000, we terminated our equity swap transaction associated with an additional 18.5 percent of CAPSA's outstanding stock and purchased the counterparty's 18.5 percent interest in CAPSA for approximately $127 million. CAPSA is a privately held Argentine company engaged in power generation and natural gas and oil production. Under the swap, we paid interest to the counterparty, on a quarterly basis, on a notional amount of $103 million at a rate of LIBOR plus 1.75 percent. In exchange, we received dividends, if any, on the CAPSA stock to the extent of the counterparty's equity interest of 18.5 percent. We also fully participated in the market appreciation or depreciation of the underlying investment whereby we realized appreciation or funded any depreciation attributable to the actual sale of the stock upon termination or expiration of the swap transaction. The termination of this swap did not have a material impact on our financial results.

We also face credit risk with respect to our non-trading activities, and take similar measures as in our trading activities to mitigate this risk. Based upon our policies and risk exposure, we do not anticipate a material effect on our financial position, operating results or cash flows resulting from counterparty non-performance.

7. Inventory

Our inventory consisted of the following at December 31:

	2000	1999
	(in millions)	
Materials and supplies	$ 78	$71
Natural gas in storage	58	2
Work in progress — Fiber	31	1
Total	$167	$74

8. Property, Plant, and Equipment

Our property, plant, and equipment consisted of the following at December 31:

	2000	1999
	(In millions)	
Property, plant, and equipment, at cost		
Pipelines	$ 7,997	$ 8,126
Power facilities	351	516
Gathering and processing systems	2,545	1,220
Production	5,932	5,415
Corporate and Other	248	196
	17,073	15,473
Less accumulated depreciation, depletion, and amortization	7,777	7,657
	9,296	7,816
Additional acquisition cost assigned to utility plant, net of accumulated amortization	2,363	2,449
Total property, plant, and equipment, net	$11,659	$10,265

Additional acquisition cost assigned to utility plant represents the excess of allocated purchase costs over historical costs of these facilities. These costs are amortized on a straight-line basis over the remaining lives of the facilities and we do not recover these excess costs in our rates.

9. Debt and Other Credit Facilities

The average interest rate on our short-term borrowings was 7.4% and 6.6% at December 31, 2000 and 1999. We had the following short-term borrowings, including current maturities of long-term debt, at December 31:

	2000	1999
	(In millions)	
Short-term credit facility	$ 455	$ —
Commercial paper	961	1,216
Other credit facilities	10	35
Current maturities of long-term debt	1,032	92
	$2,458	$1,343

Our long-term debt outstanding consisted of the following at December 31:

	2000	1999
	(In millions)	
Long-term debt		
El Paso Corporation		
Senior notes, 6.625% through 7.375%, due 2001 through 2012	$1,700	$1,100
Notes, 6.625% through 9.0%, due 2001 through 2030	1,500	1,200
Variable rate senior note due 2001, average interest for 2000 of 7.11% and 6.35% for 1999	100	100
El Paso Tennessee		
Notes, 7.25% through 10.0%, due 2008 through 2025	51	51
Debentures, 6.5% through 10.375%, due 2000 through 2005	36	42
Tennessee Gas Pipeline		
Debentures, 6.0% through 7.625%, due 2011 through 2037	1,386	1,386
El Paso Natural Gas		
Notes, 6.75% through 7.75%, due 2002 through 2003	415	415
Debentures, 7.5% and 8.625%, due 2022 and 2026	460	460
Southern Natural Gas		
Notes, 6.125% through 8.875%, due 2001 through 2008	500	500
EPEC Corporation		
Senior Note, 9.625%, due 2001	13	13
DeepTech International		
Senior note, 12.0%, due 2000	—	82
Field Services		
Notes, 7.41% through 11.5% due 2001 through 2012	511	—
Other	1	4
	6,673	5,353
Less: Unamortized discount	35	38
Current maturities	1,032	92
Long-term debt, less current maturities	$5,606	$5,223

Aggregate maturities of the principal amounts of long-term debt for the next 5 years and in total thereafter are as follows:

	(In millions)
2001	$1,032
2002	520
2003	241
2004	69
2005	289
Thereafter	4,522
Total long-term debt, including current maturities	$6,673

Other Financing Arrangements

As of December 31, 2000, we have a $2 billion, 364-day renewable credit and competitive advance facility and a $1 billion, 3-year revolving credit and competitive advance facility. These facilities replaced our $1,250 million and our $750 million revolving credit facilities in August 2000. EPNG and TGP are also designated borrowers under these facilities. The interest rate for these facilities varies and was LIBOR plus 50 basis points on December 31, 2000. No amounts were outstanding under these facilities as of December 31, 2000.

In October 2000, we established a $30 million multi-currency revolving credit facility. The 364-day facility allows us access to U.S. Dollars, English Pounds, German Marks, Norwegian Kroner, and Euros. The interest rate for this facility varies and was LIBOR plus 50 basis points on December 31, 2000. No amounts were outstanding at December 31, 2000.

In December 2000, we established a $700 million floating rate bridge facility for use in connection with our acquisition of PG&E's Texas Midstream operations. As of December 31, 2000, $455 million was outstanding under this facility. As part of our acquisition, we assumed approximately $527 million in debt, and in February 2001, we borrowed the balance of this facility and redeemed $340 million of the debt assumed.

We use a commercial paper program to manage our short-term cash requirements. Under the program we can borrow up to $1 billion. In addition, TGP and EPNG have the ability to individually borrow up to $1 billion each.

As of March 2001, TGP has $200 million and SNG has $100 million under shelf registration statements on file with the Securities and Exchange Commission.

The availability of borrowings under our credit agreements is subject to specified conditions, which we believe we currently meet. These conditions include compliance with the financial covenants and ratios required by such agreements, absence of default under such agreements, and continued accuracy of the representations and warranties contained in such agreements (including the absence of any material adverse changes). All of our senior debt issues have been given investment grade ratings by Standard & Poor's and Moody's.

Other Financial Activities

Our significant long-term debt issuances and retirements during 2000 and 1999 were as follows:

Issuances

Date	Company	Type of Issue	Interest Rate	Principal	Net Proceeds[1]	Due Date
				(In millions)		
2000						
October	El Paso	Medium-term notes	8.05%	$300	$296	2030
December	El Paso	Medium-term notes	7.38%	300	298	2012
December	El Paso	Medium-term notes	6.95%	300	297	2007
1999						
May	El Paso	Senior notes	6.75%	$500	$495	2009
July	El Paso	Senior notes	6.625%	600	596	2001
July	El Paso	Senior notes	Variable	100	100	2001
July	Sonat	Notes	7.625%	600	590	2011

[1] Net proceeds were primarily used to repay short-term borrowings and for general corporate purposes.

Retirements

Date	Company	Interest Rate	Due Date	Amount
				(In millions)
2000				
July	DeepTech International	12.00%	2000	$ 82
1999				
August	Sonat	9.50%	1999	$100
September	El Paso Natural Gas	9.45%	1999	47
October	Mojave Pipeline Company	Variable	1999	107
November	Bear Creek Capital Corporation	8.16%	1999	34

In addition, we established and drew upon a $250 million non-committed line of credit in January 2000. In March 2000, we repaid this facility.

In May 2000, we issued preferred securities of a consolidated trust, El Paso Energy Capital Trust IV. Proceeds of approximately $293 million, net of issuance costs, were used for general corporate purposes. We also received approximately $984 million from a third-party investor in 2000 as a result of the sale of a preferred interest in Clydesdale Associates, L.P., a consolidated joint venture. In 1999, we received net proceeds of $960 million from a third-party investor as a result of the sale of a preferred interest in Trinity River Associates, L.L.C., a consolidated joint venture. The proceeds from these issuances were used to repay short-term debt and for other corporate purposes. For a further discussion of these transactions, See Note 10, Securities of Subsidiaries.

In November 2000, we terminated an interest rate swap with a notional amount of $600 million and a termination date of July 2001. The swap was originally put into place to swap the 6.625% fixed interest rate on our July 1999, $600 million aggregate principal Senior Notes due 2001 with a variable interest rate. The termination of the swap did not have a material impact on our financial results.

In October 1999, Mojave Pipeline Company terminated its associated interest rate swap at a cost of approximately $5 million.

We also entered into various financing transactions with unconsolidated affiliates. See Note 17, Investments in Unconsolidated Affiliates, for a further discussion of these transactions.

Financing Activities in 2001

In February 2001, SNG issued $300 million aggregate principal amount 7.35% Notes due 2031. Proceeds of approximately $297 million, net of issuance costs, were used to pay off $100 million of SNG's 8.875% Notes due 2001, and for general corporate purposes. Also in February 2001, we issued approximately $1.8 billion zero coupon convertible debentures due 2021, with a yield to maturity of 4%. Proceeds of approximately $784 million, net of issuance costs, were used to repay short-term borrowings and for general corporate purposes. These debentures are convertible into 8,456,589 shares of our common stock which is based on a conversion rate of 4.7872 shares per $1,000 principal amount at maturity. This rate was equivalent to an initial conversion price of $94.604 per share of our common stock.

In March 2001, we issued €550 million (approximately $510 million) of euro notes at 5.75% due 2006. Proceeds of approximately $505 million, net of issuance costs, were used to repay short-term debt and for general corporate purposes. To reduce our exposure to foreign currency risk, we entered into a swap transaction exchanging the euro note for a $510 million U.S. dollar denominated obligation with a fixed interest rate of 6.61% for the five year term of the note.

10. Securities of Subsidiaries

Company-obligated Preferred Securities

In March 1998, we formed El Paso Energy Capital Trust I which issued 6.5 million of 4¾% trust convertible preferred securities for $325 million ($317 million, net of issuance costs). We own all of the Common Securities of Trust I. We used the net proceeds from the preferred securities to pay down our commercial paper. Trust I exists for the sole purpose of issuing preferred securities and investing the proceeds in 4¾% convertible subordinated debentures due 2028, their sole asset. We guarantee Trust I's preferred securities. Trust I's preferred securities are reflected as company-obligated preferred securities of consolidated trusts in our balance sheet. Distributions paid on the preferred securities are included as minority interest in our income statement.

Trust I's preferred securities are non-voting (except in limited circumstances), pay quarterly distributions at an annual rate of 4¾%, carry a liquidation value of $50 per security plus accrued and unpaid distributions and are convertible into our common shares at any time prior to the close of business on March 31, 2028, at the option of the holder at a rate of 1.2022 common shares for each Trust I Preferred Security (equivalent to a conversion price of $41.59 per common share), subject to adjustment in certain circumstances.

In May 2000, we formed El Paso Energy Capital Trust IV which issued $300 million ($293 million, net of issuance costs) of preferred securities to a third party investor. These preferred securities pay cash distributions at a floating rate equal to the three-month LIBOR plus 75 basis points. As of December 31, 2000, the floating rate was 7.49%. These preferred securities must be redeemed by Trust IV no later than November 30, 2003. Proceeds from the sale of the securities were used by Trust IV to purchase a series of our floating rate senior debentures whose yield and maturity terms mirror those of Trust IV's preferred securities. The sole assets of Trust IV are these floating rate senior debentures. We guarantee all obligations of Trust IV related to its preferred securities. At the time Trust IV issued the preferred securities, we also agreed to issue $300 million of equity securities, including, but not limited to, our common stock in one or more public offerings prior to May 31, 2003.

Minority Interests

Trinity River. During 1999, we formed Sabine River Investors, L.L.C., a wholly owned limited liability company, and other separate legal entities, to generate funds to invest in capital projects and other assets. Through Sabine, we contributed $250 million of equity capital to Trinity River Associates, L.L.C., and a third-party investor contributed $980 million. The third-party investor is entitled to an adjustable preferred return derived from Trinity's net income. Trinity used the proceeds to invest in a note receivable from Sabine collateralized by selected assets. We have the option to acquire the third-party's interest in Trinity at any time prior to June 2004. If we do not exercise this option or if the agreement is not extended, Trinity's note receivable from Sabine will mature and a portion of the proceeds will be used by Trinity to redeem the third-party interest in Trinity. The assets, liabilities, and operations of Sabine, Trinity, and other entities involved in the transaction are included in our consolidated financial statements.

Clydesdale. In May 2000, we formed Clydesdale Associates, L.P., a limited partnership, and several other separate legal entities to generate funds to invest in capital projects and other assets. Initially, we contributed $55 million of equity capital into Clydesdale and a third-party investor contributed $250 million. In December 2000, we contributed an additional $200 million into Clydesdale and a third-party investor contributed an additional $750 million. The third-party investor is entitled to an adjustable preferred return derived from Clydesdale's net income. Clydesdale used the proceeds to invest in a note receivable with us. The third-party's contributions are collateralized by production properties, rental income from real estate assets, and notes receivable from us. We have the option to acquire the third-party's interest in Clydesdale at any time prior to May 2005. If we do not exercise this option, or if the agreement is not extended, the note receivable will mature and a portion of the proceeds will be used to redeem the third-party interest in Clydesdale. The assets, liabilities, and operations of the entities involved in this transaction are included in our consolidated financial statements.

Preferred Stock of Subsidiary. In November 1996, El Paso Tennessee Pipeline Co. issued 6 million shares of 8.25% cumulative preferred stock with a par value of $50 per share for $296 million (net of issuance costs). The preferred stock is redeemable, at the option of El Paso Tennessee, after December 31, 2001, at a redemption price equal to $50 per share, plus dividends accrued and unpaid up to the date of redemption. During 2000, 1999, and 1998, dividends of approximately $25 million were paid each year on the preferred stock.

11. Commitments and Contingencies

Legal Proceedings

On August 19, 2000, a main transmission line owned and operated by EPNG ruptured at the crossing of the Pecos River near Carlsbad, New Mexico. Twelve individuals at the site were fatally injured. Eleven lawsuits brought on behalf of the twelve deceased persons have been filed against EPNG and EPEC for damages for personal injuries and wrongful death — three in state district court in Harris County, Texas *(Diane Heady, et al v. EPEC and EPNG, filed September 7, 2000; Richard Heady v. EPEC and EPNG, filed February 15, 2001; Geneva Smith v. EPEC and EPNG, filed October 23, 2000)*, two in federal district court in Albuquerque, New Mexico *(Dawson v. EPEC and EPNG, filed November 8, 2000; Jennifer Smith v. EPEC and EPNG, filed August 29, 2000)*, and six in state district court in Carlsbad, New Mexico *(Chapman, as Personal Representative of the Estate of Amy Smith Heady, v. EPEC, EPNG, and John Cole, filed February 9, 2001;* and *Chapman v. EPEC, EPNG and John Cole; Green v. EPEC, EPNG, and John Cole; Rackley, as Personal Representative of the Estate of Glenda Gail Sumler, v. EPEC, EPNG, and John Cole;* and *Rackley, as Personal Representative of the Estate of Amanda Sumler Smith, v. EPEC, EPNG, and John Cole, all filed March 16, 2001)*. In March 2001, we settled all claims in the *Heady* cases. Payments for these four claimants will be fully covered by insurance. The National Transportation Safety Board is conducting an investigation into the facts and circumstances concerning the possible causes of the rupture.

In August 2000, the Liquidating Trustee in the bankruptcy of Power Corporation of America (PCA) sued El Paso Merchant Energy, and several other power traders, in the U.S. Bankruptcy Court in Connecticut, claiming El Paso Merchant Energy improperly cancelled its contracts with PCA during the summer of 1998. The trustee alleges we breached contracts damaging PCA in the amount of $120 million. We have entered into a joint defense agreement with the other defendants. This matter will be mediated in the second quarter of 2001. In a related matter, PCA appealed the FERC's ruling that power marketers such as EPME did not have to give 60 days notice to cancel its power contracts under the Federal Power Act. PCA has appealed this decision to the United States Court of Appeals. Oral arguments were heard in January 2001 and we are awaiting the Court's decision.

In late 2000, we and several of our subsidiaries, including El Paso Natural Gas Company and El Paso Merchant Energy, were named as defendants in four purported class action lawsuits filed in state court in

California. *(Continental Forge Co. v. Southern California Gas Co., et al*, Los Angeles; *Berg v. Southern California Gas Co., et al*, Los Angeles; *John Phillip v. El Paso Merchant Energy, et al*, San Diego; *John WHK Phillip v. El Paso Merchant Energy, et al*, San Diego.) Two of these cases, filed in Los Angeles, contend generally that our entities conspired with other unrelated companies to create artificially high prices for natural gas in California; the other two cases, filed in San Diego, assert that our companies used Merchant Energy's acquisition of capacity on the EPNG pipeline to manipulate the market for natural gas in California. We have remanded each of these cases to the federal courts in California and have filed motions to dismiss in the San Diego actions. On March 20, 2001, two additional lawsuits, *The City of Los Angeles, et. al. v. Southern California Gas Company, et. al.* and *The City of Long Beach, et. al. v. Southern California Gas Company et. al.* were filed in a Los Angeles County Superior Court. These cases seek monetary damages against us and several of our subsidiaries and make similar allegations to the Continental Forge and Berg cases discussed above.

In 1999, a number of our subsidiaries were named defendants in actions brought by Jack Grynberg on behalf of the U.S. Government under the False Claims Act. Generally, these complaints allege an industry-wide conspiracy to under report the heating value as well as the volumes of the natural gas produced from federal and Native American lands, which deprived the U.S. Government of royalties. These matters have been consolidated for pretrial purposes. (In re: Natural Gas Royalties *Qui Tam* Litigation, U.S. District Court for the District of Wyoming.)

A number of our subsidiaries are named defendants in an action styled *Quinque Operating Company, et al v. Gas Pipelines and Their Predecessors, et al*, filed in 1999 in the District Court of Stevens County, Kansas. This class action complaint alleges that the defendants mismeasured natural gas volumes and heating content of natural gas on non-federal and non-Native American lands. The Quinque complaint, once transferred to the same court handling the Grynberg complaint, has been sent back to the Kansas State Court for further proceedings.

In February 1998, the United States and the State of Texas filed in a U.S. District Court a Comprehensive Environmental Response, Compensation and Liability Act (CERCLA) cost recovery action against fourteen companies, including some of our current and former affiliates, related to the Sikes Disposal Pits Superfund Site located in Harris County, Texas. The suit claims that the United States and the State of Texas have spent over $125 million in remediating Sikes, and seeks to recover that amount plus interest from the defendants to the suit. The EPA has recently indicated that it may seek an additional amount up to $30 million plus interest in indirect costs from the defendants under a new cost allocation methodology. Defendants are challenging this allocation policy. Although an investigation relating to Sikes is ongoing, we believe that the amount of material, if any, disposed at Sikes by our former affiliates was small, possibly *de minimis*. However, the plaintiffs have alleged that the defendants are each jointly and severally liable for the entire remediation costs and have also sought a declaration of liability for future response costs such as groundwater monitoring.

TGP is a party in proceedings involving federal and state authorities regarding the past use of a lubricant containing polychlorinated biphenyls (PCBs) in its starting air systems. TGP has executed a consent order with the EPA governing the remediation of some compressor stations and is working with the EPA and the relevant states regarding those remediation activities. TGP is also working with the Pennsylvania and New York environmental agencies regarding remediation and post-remediation activities at the Pennsylvania and New York stations.

In November 1988, the Kentucky environmental agency filed a complaint in a Kentucky state court alleging that TGP discharged pollutants into the waters of the state and disposed of PCBs without a permit. The agency sought an injunction against future discharges, an order to remediate or remove PCBs, and a civil penalty. TGP entered into agreed orders with the agency to resolve many of the issues raised in the original allegations, received water discharge permits from the agency for its Kentucky compressor stations, and continues to work to resolve the remaining issues. The relevant Kentucky compressor stations are being characterized and remediated under a consent order with the EPA.

We are also a named defendant in numerous lawsuits and a named party in numerous governmental proceedings arising in the ordinary course of our business.

While the outcome of the matters discussed above cannot be predicted with certainty, we do not expect the ultimate resolution of these matters will have a material adverse effect on our financial position, operating results, or cash flows.

Environmental

We are subject to extensive federal, state, and local laws and regulations governing environmental quality and pollution control. These laws and regulations require us to remove or remedy the effect on the environment of the disposal or release of specified substances at current and former operating sites. As of December 31, 2000, we had a reserve of approximately $274 million for expected remediation costs, including approximately $257 million for associated onsite, offsite and groundwater technical studies, and approximately $17 million for other costs which we anticipate incurring through 2027. In addition, we expect to make capital expenditures for environmental matters of approximately $103 million in the aggregate for the years 2001 through 2007. These expenditures primarily relate to compliance with air regulations.

Since 1988, TGP has been engaged in an internal project to identify and deal with the presence of PCBs and other substances, including those on the EPA List of Hazardous Substances, at compressor stations and other facilities it operates. While conducting this project, TGP has been in frequent contact with federal and state regulatory agencies, both through informal negotiation and formal entry of consent orders, to ensure that its efforts meet regulatory requirements.

In May 1995, following negotiations with its customers, TGP filed a Stipulation and Agreement (the Environmental Stipulation) with FERC that established a mechanism for recovering a substantial portion of the environmental costs identified in its internal project. The Environmental Stipulation was effective July 1, 1995, and as of December 31, 1999, all amounts have been collected from customers. Refunds may be required to the extent actual eligible expenditures are less than amounts collected.

We have been designated and have received notice that we could be designated, or have been asked for information to determine whether we could be designated as a Potentially Responsible Party (PRP) with respect to 29 sites under the Comprehensive Environmental Response, Compensation and Liability Act (CERCLA or Superfund) or state equivalents. We sought to resolve our liability as a PRP at these Superfund sites through indemnification by third parties and/or settlements which provide for payment of our allocable share of remediation costs. As of December 31, 2000, we have estimated our share of the remediation costs at these sites to be between $59 million and $194 million and have provided reserves that we believe are adequate for such costs. Since the clean-up costs are estimates and are subject to revision as more information becomes available about the extent of remediation required, and because in some cases we have asserted a defense to any liability, our estimates could change. Moreover, liability under the federal Superfund statute is joint and several, meaning that we could be required to pay in excess of our pro rata share of remediation costs. Our understanding of the financial strength of other PRPs has been considered, where appropriate, in the determination of our estimated liabilities. We presently believe that the costs associated with these Superfund sites will not have a material adverse effect on our financial position, operating results, or cash flows.

It is possible that new information or future developments could require us to reassess our potential exposure related to environmental matters. We may incur significant costs and liabilities in order to comply with existing environmental laws and regulations. It is also possible that other developments, such as increasingly strict environmental laws and regulations, and claims for damages to property, employees, other persons and the environment resulting from our current or past operations, could result in substantial costs and liabilities in the future. As this information becomes available, or other relevant developments occur, we will adjust our accrual amounts accordingly. While there are still uncertainties relating to the ultimate costs we may incur, based upon our evaluation and experience to date, we believe the recorded reserves are adequate. For a further discussion of specific environmental matters, see Legal Proceedings above.

Rates and Regulatory Matters

In April 2000, the California Public Utilities Commission (CPUC) filed a complaint alleging that El Paso Natural Gas' sale of capacity to Merchant Energy was anti-competitive and an abuse of the affiliate relationship under FERC's policies. The CPUC served data requests to us, which have been either substantially answered or contested. In August 2000, the CPUC filed a motion requesting that the contract between EPNG and Merchant Energy be terminated. Other parties in the proceedings have requested that the original complaint be set for hearings and that Merchant Energy pay back any profits it has earned under the contract. The matter is pending at FERC.

In February 2001, EPNG completed its open season on 1,221 MMcf/d of capacity held by Merchant Energy through May 2001 and all the capacity was re-subscribed. Contracts were awarded to 30 different entities, including 271 MMcf/d to Merchant Energy, all at published tariff rates under contracts with durations from 17 months to 15 years.

While we cannot predict with certainty the final outcome or the timing of the resolution of all of our rates and regulatory matters, we believe the ultimate resolution of these issues will not have a material adverse effect on our financial position, results of operations, or cash flows.

Capital Commitments and Purchase Obligations

At December 31, 2000, we had capital and investment commitments of $1.2 billion primarily relating to our production, pipeline, and international power activities. Our other planned capital and investment projects are discretionary in nature, with no substantial capital commitments made in advance of the actual expenditures. In connection with the financing commitments on one of our joint ventures, TGP has entered into unconditional purchase obligations for products and services totaling $122 million at December 31, 2000. TGP's annual obligations under these agreements are $21 million for the years 2001, 2002, 2003, 2004 and 2005, and $17 million in total thereafter.

Operating Leases

We lease property, facilities and equipment under various operating leases. In 1995, El Paso New Chaco Company (EPNC) entered into an unconditional lease for the Chaco Plant. The lease term expires in 2002, at which time EPNC has an option, and an obligation upon the occurrence of various events, to purchase the plant for a price sufficient to pay the amount of the $77 million construction financing, plus interest and other expenses. If EPNC does not purchase the plant at the end of the lease term, it has an obligation to pay a residual guaranty amount equal to approximately 87 percent of the amount financed, plus interest. We unconditionally guaranteed all obligations of EPNC under this lease.

Minimum annual rental commitments at December 31, 2000, were as follows:

Year Ending December 31,	Operating Leases (In millions)
2001	$ 41
2002	34
2003	27
2004	26
2005	27
Thereafter	59
Total	$214

Aggregate minimum commitments have not been reduced by minimum sublease rentals of approximately $14 million due in the future under noncancelable subleases.

Rental expense on our operating leases for the years ended December 31, 2000, 1999, and 1998 was $58 million, $37 million, and $39 million.

Guarantees

At December 31, 2000, we had parental guarantees of approximately $2 billion in connection with our international development activities and various other projects, including approximately $1 billion associated with our investments in unconsolidated affiliates as discussed in Note 17. We believe that these parties will be able to perform under the guaranteed transactions, that no payments will be required or losses incurred by us under these guarantees. We also had outstanding letters of credit of approximately $233 million at December 31, 2000. At December 31, 1999, parental guarantees totaled approximately $1 billion and outstanding letters of credit were $170 million.

12. Retirement Benefits

Pension Benefits

Prior to January 1, 1997, we maintained a defined benefit pension plan that covered substantially all of our employees. Pension benefits were based on years of credited service and final five year average compensation, subject to maximum limitations as defined in that plan. Effective January 1, 1997, the plan was amended to provide benefits determined by a cash balance formula and to include employees added as a result of our merger with El Paso Tennessee and other acquisitions prior to 1997. Employees who were pension plan participants on December 31, 1996, receive the greater of cash balance benefits or prior plan benefits accrued through December 31, 2001.

Following our merger with Sonat, we offered an early retirement incentive program to Sonat employees who were at least 50 years of age with 10 years of service as of December 31, 1999, and who terminated employment by June 30, 2000. Total charges as a result of the early retirement program were approximately $8 million.

Effective January 1, 2000, the Sonat pension plan was merged into our pension plan. Sonat employees who were participants in the Sonat pension plan on the Sonat merger effective date receive the greater of cash balance benefits or the Sonat plan benefits accrued through December 31, 2004.

Other Postretirement Benefits

We provide postretirement medical benefits for certain closed groups of retired employees of EPNG, El Paso Tennessee, and Sonat, and limited postretirement life insurance benefits for current and retired employees. Other postretirement employee benefits (OPEB) are prefunded to the extent such costs are recoverable through rates.

Under our early retirement incentive program for Sonat employees and employees of PG&E's Texas Midstream operations, participating eligible employees were allowed to keep postretirement medical and life benefits commencing at the later of age 55 or retirement. Total charges associated with the Sonat incentive program and the elimination of retiree benefits for future retirees were $29 million and were accrued as of December 31, 1999. The total liabilities for the PG&E group were $8 million and were accrued as of December 31, 2000. Medical benefits for these closed groups of retirees may be subject to deductibles, co-payment provisions, and other limitations and dollar caps on the amount of employer costs. We have reserved the right to change these benefits.

The following table sets forth the change in benefit obligation, change in plan assets, reconciliation of funded status, and components of net periodic benefit cost for pension benefits and other postretirement benefits as of and for the twelve month period ended September 30:

	Pension Benefits		Postretirement Benefits	
	2000	1999	2000	1999
	(In millions)			
Change in benefit obligation				
Benefit obligation at beginning of period	$ 859	$ 953	$ 489	$ 494
Service cost	18	21	—	2
Interest cost	62	57	35	33
Participant contributions	—	—	10	8
Plan amendments	—	(18)	—	(13)
Settlements, curtailments and special termination benefits	—	3	—	6
Acquisition of PG&E's Texas Midstream operations	—	—	8	—
Actuarial (gain) or loss	6	(92)	(22)	24
Benefits paid	(94)	(65)	(64)	(65)
Benefit obligation at end of period	$ 851	$ 859	$ 456	$ 489
Change in plan assets				
Fair value of plan assets at beginning of period	$1,158	$1,126	$ 126	$ 112
Actual return on plan assets	128	90	11	9
Employer contributions	23	7	70	62
Participant contributions	—	—	10	8
Benefits paid	(94)	(65)	(64)	(65)
Fair value of plan assets at end of period	$1,215	$1,158	$ 153	$ 126
Reconciliation of funded status				
Funded status at end of period	$ 364	$ 299	$(303)	$(363)
Fourth quarter contributions and income	2	31	16	15
Unrecognized net actuarial gain	(232)	(246)	(28)	(3)
Unrecognized net transition obligation	(1)	—	39	46
Unrecognized prior service cost	(42)	(46)	(10)	(11)
Prepaid (accrued) benefit cost at December 31,	$ 91	$ 38	$(286)	$(316)

Included in the pension benefits information are plans in which the projected benefit obligation and accumulated benefit obligation for pension plans with accumulated benefit obligations in excess of plan assets were $37 million and $31 million as of December 31, 2000, and $57 million and $53 million as of December 31, 1999.

The current liability portion of the postretirement benefits was $46 million as of December 31, 2000 and 1999, respectively. Benefit obligations are based upon actuarial estimates as described below.

	Pension Benefits			Postretirement Benefits		
	Year Ended December 31,					
	2000	1999	1998	2000	1999	1998
	(In millions)					
Benefit cost for the plans includes the following components						
Service cost	$ 18	$ 23	$ 22	$ —	$ 2	$ 2
Interest cost	62	65	64	35	33	33
Expected return on plan assets	(113)	(104)	(96)	(7)	(8)	(6)
Amortization of net actuarial gain	(10)	(2)	(2)	—	(1)	(2)
Amortization of transition obligation	2	2	—	7	10	11
Amortization of prior service cost	(4)	(2)	(2)	(1)	(1)	(1)
Settlements, curtailment, and special termination benefits	—	1	(1)	—	29	6
Net benefit cost	$ (45)	$ (17)	$(15)	$ 34	$64	$43

	Pension Benefits		Postretirement Benefits	
	2000	1999	2000	1999
Weighted average assumptions				
Discount rate	7.75%	7.50%	7.75%	7.50%
Expected return on plan assets	10.00%	9.98%	7.50%	7.50%
Rate of compensation increase	4.50%	4.64%	N/A	N/A

Actuarial estimates for our postretirement benefits plans assumed a weighted average annual rate of increase in the per capita costs of covered health care benefits of 10 percent in 2000, gradually decreasing to 6 percent by the year 2008. Assumed health care cost trends have a significant effect on the amounts reported for other postretirement benefit plans. A one-percentage point change in assumed health care cost trends would have the following effects:

	2000	1999
	(In Millions)	
One Percentage Point Increase		
Aggregate of Service Cost and Interest Cost	$ 1	$ 2
Accumulated Postretirement Benefit Obligation	$ 19	$ 23
One Percentage Point Decrease		
Aggregate of Service Cost and Interest Cost	$ (1)	$ (2)
Accumulated Postretirement Benefit Obligation	$(18)	$(21)

Retirement Savings Plan

We maintain a defined contribution plan covering all of our employees. We match 75 percent of participant basic contributions of up to 6 percent, with the matching contribution being made in our stock. Prior to our Sonat merger, Sonat matched 100 percent of participant basic contributions of up to 6 percent. Amounts expensed under the plan were approximately $14 million, $16 million and $16 million for the years ended December 31, 2000, 1999, and 1998, respectively.

13. Capital Stock

We have 50,000,000 shares of authorized preferred stock, par value $0.01 per share, none of which have been issued, but of which 7,500,000 shares have been designated as Series A Junior Participating Preferred Stock and reserved for issuance pursuant to our preferred stock purchase rights plan.

14. Stock-Based Compensation

During 2000, 1999, and 1998, we granted stock options under various stock option plans. We account for these plans using Accounting Principles Board Opinion No. 25 and its related Interpretations. In 1995, the Financial Accounting Standards Board issued SFAS No. 123, *Accounting for Stock-Based Compensation* which, if fully adopted, changes the methods companies use in determining expense related to their stock option plans. Adoption of the expense recognition provisions of SFAS No. 123 was optional and we elected not to apply its provisions. However, we are required to present the following pro forma disclosures as if we had adopted SFAS No. 123.

Under our existing stock option plans, we are authorized to issue shares of common stock to employees and non-employee directors pursuant to awards granted as incentive stock options (intended to qualify under Section 422 of the Internal Revenue Code), non-qualified stock options, restricted stock, stock appreciation rights (SARs), phantom stock options, and performance units. We have reserved approximately 53 million shares of common stock for issuance pursuant to existing and future stock awards. As of December 31, 2000, approximately 27 million shares remained unissued.

Non-qualified Stock Options

We granted non-qualified stock options to our employees in 2000, 1999, and 1998. These stock options have contractual terms of 10 years and generally vest after completion of one to five years of continuous employment from the grant date. We also granted options to non-employee members of the Board of Directors at fair market value on the grant date that are exercisable immediately. Under the terms of certain plans, we may grant SARs to certain holders of stock options. SARs are subject to the same terms and conditions as the related stock options. As of December 31, 2000, we have no SARs outstanding.

A summary of the status of our stock options as of December 31, 2000, 1999, and 1998 is presented below:

	Stock Options					
	2000		1999		1998	
	# Shares of Underlying Options	Weighted Average Exercise Prices	# Shares of Underlying Options	Weighted Average Exercise Prices	# Shares of Underlying Options	Weighted Average Exercise Prices
Outstanding at beginning of the year	22,511,704	$32.80	15,331,658	$25.46	13,198,433	$22.86
Granted	1,065,110	$41.35	9,639,750	$41.02	3,651,550	$32.34
Exercised	3,648,752	$25.99	2,092,953	$18.26	1,262,775	$17.77
Forfeited	263,911	$38.44	366,751	$31.15	255,550	$27.99
Outstanding at end of year	19,664,151	$34.43	22,511,704	$32.80	15,331,658	$25.46
Exercisable at end of year	12,431,102	$30.51	12,996,454	$26.71	8,486,647	$22.35

The fair value of each stock option granted is estimated on the date of grant using the Black-Scholes option-pricing model with the following weighted-average assumptions:

Assumption:	2000	1999	1998
Expected Term in Years	7	7	5
Expected Volatility	23.9%	21.9%	20.3%
Expected Dividends	3.0%	3.0%	3.0%
Risk-Free Interest Rate	5.0%	6.3%	4.6%

The Black-Scholes weighted average fair value of options granted during 2000, 1999 and 1998 was $10.16, $11.42, and $7.00, respectively.

Options outstanding as of December 31, 2000 are summarized below:

Range of Exercise Prices	Options Outstanding: Number Outstanding at 12/31/00	Options Outstanding: Weighted Average Remaining Contractual Life	Options Outstanding: Weighted Average Exercise Price	Options Exercisable: Number Exercisable at 12/31/00	Options Exercisable: Weighted Average Exercise Price
$ 7.15 to $21.40	3,468,451	3.6	$15.93	3,468,451	$15.93
$21.41 to $35.70	5,119,933	6.2	$30.32	4,644,633	$29.90
$35.71 to $42.90	9,531,247	8.7	$41.08	2,980,798	$41.01
$42.91 to $71.50	1,544,520	6.9	$48.61	1,337,220	$47.02
$ 7.15 to $71.50	19,664,151	7.0	$34.43	12,431,102	$30.51

Pro Forma Net Income and Net Income Per Common Share

Had the compensation expense for our stock-based compensation plans been determined applying the provisions of SFAS No. 123, our net income and net income per common share for 2000, 1999, and 1998 would approximate the pro forma amounts below:

	December 31, 2000		December 31, 1999		December 31, 1998	
	As Reported	Pro Forma	As Reported	Pro Forma	As Reported	Pro Forma
SFAS No. 123 charge, pretax	$ —	$ 95	$ —	$ 160	$ —	$ 63
APB No. 25 charge, pretax	$ 38	$ —	$ 145	$ —	$ 51	$ —
Net income (loss)	$ 652	$ 614	$ (255)	$ (267)	$ (306)	$ (313)
Basic earnings (loss) per common share	$2.83	$2.66	$(1.12)	$(1.17)	$(1.35)	$(1.39)
Diluted earnings (loss) per common share	$2.73	$2.57	$(1.12)	$(1.17)	$(1.35)	$(1.39)

The effects of applying SFAS No. 123 in this pro forma disclosure are not indicative of future amounts. SFAS No. 123 does not apply to awards granted prior to the 1995 fiscal year.

Restricted Stock

Under our various stock-based compensation plans, a limited number of shares of restricted common stock may be granted at no cost to certain key officers and employees. These shares carry voting and dividend rights; however, sale or transfer of the shares is restricted. These restricted stock awards vest over a specific period of time and/or if we achieve certain performance targets. Restricted stock awards representing 0.4 million, 1.4 million, and 0.6 million shares were granted during 2000, 1999, and 1998, respectively, with a weighted average grant date fair value of $34.82, $35.10, and $32.40 per share, respectively. At December 31, 2000, 1.5 million shares of restricted stock were outstanding. The value of these shares is determined based on the fair market value on the date performance targets are achieved, and this value is charged to compensation expense ratably over the required service or restriction period. For 2000, 1999, and 1998, these charges totaled $13 million, $69 million, and $29 million. Included in deferred compensation at December 31, 2000, is $69 million related to options that will be converted at the holders election into common stock at the end of their vesting period. These options met all performance targets in December 2000.

Performance Units and Phantom Stock Options

We award eligible employees phantom stock options that are payable in cash. We also award eligible employees and officers performance units that are payable in cash or stock at the end of the vesting period. The final value of the performance units may vary according to the plan under which they are granted, but is usually based on our common stock price at the end of the vesting period. The value of the performance units is charged ratably to compensation expense over the vesting period with periodic adjustments to account for the fluctuation in the market price of our stock. Amounts charged to compensation expense in 2000, 1999, and 1998 were $25 million, $30 million, and $13 million. Included in the 1999 amount is $22 million related to the accelerated vesting of the performance units due to the change in control resulting from the merger with Sonat. In March 2001, we paid our phantom stock options, resulting in a charge of $51 million.

Employee Stock Purchase Program

In October 1999, we implemented an employee stock purchase plan under Section 423 of the Internal Revenue Code. The plan allows participating employees the right to purchase common stock on a quarterly basis at 85 percent of the lower of the market price at the beginning of the plan period or at the end of each calendar quarter. Two million shares of common stock are authorized for issuance under this plan. We issued 346,332 shares at $32.33 per share in 2000, and 139,842 shares at $33.10 per share in 1999. Funds we receive may be used for general corporate purposes. However, we record a liability for the withholdings not yet applied towards the purchase of common stock. We bear all expenses associated with administering the plan, except for costs, including any applicable taxes, associated with the participants' sale of common stock.

15. Segment Information

Our business activities are segregated into four segments: Pipelines, Merchant Energy, Field Services, and Production. These segments are strategic business units that offer a variety of different energy products and services. We manage each segment separately as each business requires different technology and marketing strategies. During 2000, we combined our International and Merchant Energy segments to reflect the ongoing globalization of Merchant Energy's strategy and its operating activities. All prior periods have been restated to reflect the current year presentation.

Our Pipeline segment provides natural gas transmission services in the U.S. We conduct our activities through five wholly owned and two partially owned interstate systems along with a liquified natural gas terminalling facility and various natural gas storage facilities.

Our Merchant Energy segment is involved in a broad range of activities in the energy marketplace, including asset ownership, trading and risk management and financial services. We buy, sell, and trade natural gas, power, crude oil, refined products, coal and other energy commodities throughout the world, and own or have interests in 64 power generation plants in 16 countries.

Our Field Services segment provides natural gas gathering, storage, products extraction, fractionation, dehydration, purification, compression and intrastate transmission services. Field Services' assets are located in some of the most prolific and active production areas in the U.S., including the San Juan Basin, east and south Texas, Louisiana and the Gulf of Mexico.

Our Production segment is engaged in the exploration for and the acquisition, development, and production of natural gas, oil and natural gas liquids in the major producing basins of the United States. Production has onshore and coal seam operations and properties in 11 states and offshore operations and properties in federal and state waters in the Gulf of Mexico. We also have exploration and production rights in Turkey.

The accounting policies of the individual segments are the same as those described in Note 1. Since earnings on equity investments can be a significant component of earnings in several of our segments, we evaluate segment performance based on earnings before interest and taxes (EBIT) instead of operating income. To the extent practicable, results of operations for the years ended December 31, 1999 and 1998 have been reclassified to conform to the current business segment presentation, although such results are not necessarily indicative of the results which would have been achieved had the revised business segment structure been in effect during that period.

	Segments As of or for the Year Ended December 31, 2000					
	Pipelines	Merchant Energy	Field Services	Production	Other[1]	Total
	(In millions)					
Revenue from external customers						
Domestic	$1,549	$18,464	$ 598	$ 298	$ 3	$20,912
Foreign	—	1,038	—	—	—	1,038
Intersegment revenue	148	19	85	224	(476)	—
Merger-related costs and asset impairment charges	—	—	11		80	91
Depreciation, depletion, and amortization	244	27	67	212	39	589
Operating income (loss)	754	433	76	196	(128)	1,331
Other income (loss)	68	130	26	—	(5)	219
Earnings (loss) before interest and taxes	822	563	102	196	(133)	1,550
Extraordinary items, net of income taxes	89	—	(19)	—	—	70
Assets						
Domestic	8,833	9,758	3,241	1,819	1,862	25,513
Foreign	—	1,932	—	—	—	1,932
Capital expenditures and investments in unconsolidated affiliates	493	941	439	484	1,059	3,416
Total investments in unconsolidated affiliates	510	1,910	374	7	57	2,858

(1) Includes Corporate and eliminations as well as telecommunications which has not had significant activity.

	Segments As of or for the Year Ended December 31, 1999					
	Pipelines	Merchant Energy	Field Services	Production	Other[1]	Total
	(In millions)					
Revenue from external customers						
Domestic	$1,720	$7,893	$ 388	$ 108	$ 9	$10,118
Foreign	—	591	—	—	—	591
Intersegment revenue	51	36	78	365	(530)	—
Merger-related costs and asset impairment charges	90	67	8	31	361	557
Ceiling test charges	—	—	—	352	—	352
Depreciation, depletion, and amortization	275	47	60	210	16	608
Operating income (loss)	668	(91)	38	(258)	(390)	(33)
Other income	51	94	47	1	31	224
Earnings (loss) before interest and taxes	719	3	85	(257)	(359)	191
Assets						
Domestic	8,919	2,103	1,457	1,393	1,459	15,331
Foreign	—	1,336	—	—	—	1,336
Capital expenditures and investments in unconsolidated affiliates	455	1,239	121	365	30	2,210
Total investments in unconsolidated affiliates	618	1,274	266	6	13	2,177

(1) Includes Corporate and eliminations.

	Segments As of or for the Year Ended December 31, 1998					
	Pipelines	Merchant Energy	Field Services	Production	Other(1)	Total
	(In millions)					
Revenue from external customers						
Domestic	$1,608	$7,181	$ 212	$ 174	4	$ 9,179
Foreign	—	381	—	—		381
Intersegment revenue	88	22	65	361	(536)	—
Merger-related costs and asset impairment charges	—	—	—	15	—	15
Ceiling test charges	—	—	—	1,035	—	1,035
Depreciation, depletion, and amortization	255	17	49	292	11	624
Operating income (loss)	752	(37)	62	(939)	(73)	(235)
Other income	59	65	14	3	42	183
Earnings (loss) before interest and taxes	811	28	76	(936)	(31)	(52)
Assets						
Domestic	8,659	1,564	1,461	1,544	573	13,801
Foreign	—	654	—	—	—	654
Capital expenditures and investments in unconsolidated affiliates	401	582	453	581	22	2,039
Total investments in unconsolidated affiliates	517	480	87	6	14	1,104

(1) Includes Corporate and eliminations.

The reconciliations of EBIT to income (loss) before extraordinary items and the cumulative effect of accounting change are presented below.

	For the Year Ended December 31,		
	2000	1999	1998
	(In millions)		
Total EBIT for segments	$1,550	$ 191	$ (52)
Interest and debt expense	538	453	387
Minority interest	144	61	37
Income tax expense (benefit)	286	(81)	(170)
Income (loss) before extraordinary items and cumulative effect of accounting change	$ 582	$(242)	$(306)

Prior to the current year, we had no customers whose revenues exceeded 10 percent of our total revenues. In 2000, Merchant Energy had revenues of $2.1 billion from subsidiaries of Enron Corp. We did not have revenues in excess of 10 percent with any other customer in 2000.

16. Supplemental Cash Flow Information

The following table contains supplemental cash flow information for the years ended December 31:

	2000	1999	1998
	(In millions)		
Interest paid	$591	$421	$386
Income tax payments (refunds)	29	9	(86)

See Notes 2 and 17, for a discussion of the non-cash investing transactions related to our acquisitions.

17. Investments in and Advances to Unconsolidated Affiliates (Unaudited)

We hold investments in various unconsolidated affiliates which are accounted for using the equity method of accounting. Our principal equity method investees are international pipelines, interstate pipelines, power generation plants, and gathering systems. Our investment balance includes unamortized purchase price differences of $415 million and $105 million as of December 31, 2000 and 1999, that are being amortized over the remaining life of the unconsolidated affiliate's underlying assets. Our investments in and advances to our unconsolidated affiliates are as follows:

	Net Ownership Interest December 31, 2000	Year Ended December 31, 2000	1999
		(In millions)	
Bolivia to Brazil Pipeline	8%	$ 53	$ 45
CAPSA/CAPEX	45%	282	145
CE Generation	50%	354	334
Chaparral	20%	268	373
Citrus Corporation	50%	474	422
East Asia Power	46%	118	144
Energy Partners	30%	368	280
Korea Independent Energy Corporation	50%	108	—
Photon Investors	42%	136	—
Porto Velho	50%	99	—
Samalayuca Power	40%	93	130
Other	various	562	564
		$2,915	$2,437

Our equity earnings (losses) from our unconsolidated affiliates are as follows:

	2000	1999	1998
		(In millions)	
Bolivia to Brazil Pipeline	$ —	$ 4	$ —
CAPSA/CAPEX	4	3	—
CE Generation	35	24	—
Chaparral	(5)	(8)	—
Citrus Corporation	51	25	24
East Asia Power	(32)	—	—
Energy Partners	20	18	1
Porto Velho	1	—	—
Samalayuca Power	17	17	11
Other	36	12	37
	$127	$ 95	$ 73

Summarized financial information of our proportionate share of our unconsolidated affiliates is as follows:

	Year Ended December 31, 2000	1999	1998
		(In millions)	
Operating results data:			
Revenues and other income	$1,118	$930	$579
Costs and expenses	952	814	492
Income from continuing operations	166	116	87
Net income	127	95	73

	December 31,	
	2000	1999
	(In millions)	
Financial position data:		
Current assets	$1,064	$ 589
Non-current assets	7,812	5,197
Short-term debt	311	249
Other current liabilities	635	321
Long-term debt	2,676	2,505
Other non-current liabilities	2,922	608
Minority interest	36	9
Equity in net assets	2,296	2,094

The following table shows revenues and charges from our unconsolidated affiliates:

	2000	1999	1998
	(In millions)		
Natural gas sales	$104	—	—
Power purchases	43	—	—
Management fee income	81	20	—
Reimbursement for costs	44	17	4
Interest income	10	5	—
Interest expense	49	2	—

Chaparral Investors

During 1999, we contributed approximately $120 million of equity capital and assets to a newly formed limited liability company, Chaparral. A third-party financial investor contributed approximately $123 million on which they earn a preferred return. In connection with this transaction, Chaparral formed a wholly owned subsidiary, Mesquite. Merchant Energy manages both Chaparral and Mesquite. In January 2000, we acquired an additional interest in Chaparral in exchange for a $160 million contingent interest promissory note. The maturity date of the note is the earlier of December 2019, or upon the occurrence of events specified in the note. The note carries a variable interest rate not to exceed 12.75 percent. At December 31, 1999, we had a note payable of $121 million to Chaparral which was payable upon demand and carried a variable interest rate which was 6.4%. This note was repaid in 2000. We also had a note receivable from Mesquite which had a balance of $262 million at December 31, 1999. This note was payable on demand and had a variable rate which was 8.3%. This note was repaid by Mesquite in 2000. During 2000, we issued a note payable to Mesquite. The note is payable on demand and had a balance of $241 million at a rate of 7.3% as of December 31, 2000.

During the first quarter of 2000, Chaparral completed its acquisitions of several domestic non-utility generation assets including equity interests in eleven natural gas-fired combined generation facilities in California, two natural gas-fired electric generation plants located in Dartmouth, Massachusetts and Pawtucket, Rhode Island, and all the outstanding shares of Bonneville Pacific Corporation, which owns a 50 percent interest in a power generation facility. Chaparral also acquired several operating companies which provide the services required to operate and maintain these newly acquired facilities and a natural gas service company which provides fuel procurement services to eight of Chaparral's natural gas-fired combined generation facilities in California. Chaparral acquired these assets from us in exchange for notes payable in the amount of $385 million. In March 2000, Chaparral's third-party investor increased its overall investment in Chaparral by $1,027 million. The proceeds were used by Chaparral to repay $647 million of notes from us, to make a $278 million contribution to a trust as provided in the Chaparral agreement, to invest in a note with us, and to fund transaction costs. Also, in March 2000, we issued mandatorily convertible preferred stock to a trust we control. Upon the occurrence of certain negative events, the trustee of the trust may be required to remarket this preferred stock on terms that are designed to generate $1 billion to distribute to the third party investor.

Under our management agreement with Chaparral, we earn a performance based management fee. We are also reimbursed for expenses we incur on behalf of Chaparral. For 2000, our management fee related to Chaparral was $100 million and this fee included an $80 million performance-based component and a $20 million reimbursement for costs we incurred on behalf of Chaparral. This fee was collected and recognized ratably throughout the year as management services were provided.

We also sell natural gas and buy power from qualifying power facilities owned by Chaparral.

Photon Investors

During 2000, we contributed $44 million of equity capital and assets to a newly formed limited liability company, Photon Investors, L.L.C., which acquires and holds telecommunications assets. A third-party financial investor contributed $60 million on which they earn a preferred return. In connection with this transaction, Photon formed a wholly owned subsidiary, Quanta Investors, L.L.C. Our subsidiary manages both Photon and Quanta. During 2000, we entered into a credit agreement with Quanta, with a commitment by us to lend up to $500 million, of which approximately $94 million was advanced and outstanding at December 31, 2000. These amounts are evidenced by a subordinated promissory note, payable on the earlier of Quanta's liquidation date or any date agreed by the parties to the note. We also have a demand note payable to Quanta with a balance of approximately $61 million at December 31, 2000. Both the credit agreement and the demand note carry a variable interest rate, which was 9.57% per annum during 2000. Our investment in Photon is being accounted for using the equity method of accounting.

El Paso Energy Partners

During the third quarter of 2000, Energy Partners completed a public offering of 4.6 million common units. The offering reduced our common units ownership interest from 32.5 percent to 27.8 percent. This transaction had no effect on our general partner interest or our non-managing member interest. Also, in the third quarter, we received $170 million of Series B preference units in exchange for the transfer of natural gas storage businesses of Crystal Gas Storage, Inc., our wholly owned subsidiary, to Energy Partners. These preference units accrue dividends at a rate of 10 percent on a cumulative basis, and are redeemable at the option of Energy Partners.

In the first quarter of 2001, as a result of our merger with Coastal, Energy Partners sold its interest in several offshore assets. These sales consisted of interests in seven natural gas pipeline systems, a dehydration facility and two offshore platforms. Proceeds from these sales were approximately $135 million and resulted in a loss to the partnership of approximately $23 million. As consideration for these sales, we committed to pay Energy Partners a series of payments totaling $29 million. This amount, as well as our proportional share of the losses on the sale of the partnership's assets, will be recorded as a charge in our income statement in the first quarter of 2001.

18. Supplemental Selected Quarterly Financial Information (Unaudited)

Financial information by quarter is summarized below.

	Quarters Ended			
	December 31	September 30	June 30	March 31
	(In millions, except per common share amounts)			
2000				
Operating revenues[1]	$7,543	$7,025	$4,250	$3,132
Merger-related costs and asset impairment charges	45	—	46	—
Operating income	383	296	320	332
Income before extraordinary items	146	137	134	165
Extraordinary items, net of income taxes	(19)	—	—	89
Net income	127	137	134	254
Basic earnings (loss) per common share				
Income before extraordinary items	$ 0.63	$ 0.59	$ 0.58	$ 0.72
Extraordinary items, net of income taxes	(0.08)	—	—	0.39
Net income	$ 0.55	$ 0.59	$ 0.58	$ 1.11
Diluted earnings (loss) per common share				
Income before extraordinary items	$ 0.61	$ 0.57	$ 0.56	$ 0.70
Extraordinary items, net of income taxes	(0.08)	—	—	0.37
Net income	$ 0.53	$ 0.57	$ 0.56	$ 1.07

	Quarters Ended			
	December 31	September 30	June 30	March 31
	(In millions, except per common share amounts)			
1999				
Operating revenues[1]	$2,464	$3,296	$2,647	$2,302
Merger-related costs and asset impairment charges	364	58	131	4
Ceiling test charges	—	—	—	352
Operating income (loss)	(141)	144	117	(153)
Income (loss) before cumulative effect of accounting change	(178)	39	38	(141)
Cumulative effect of accounting change, net of income taxes	—	—	—	(13)
Net income (loss)	(178)	39	38	(154)
Basic earnings (loss) per common share				
Income (loss) before cumulative effect of accounting change	$(0.78)	$ 0.17	$ 0.17	$(0.62)
Cumulative effect of accounting change, net of income taxes	—	—	—	(0.06)
Net income (loss)	$(0.78)	$ 0.17	$ 0.17	$(0.68)
Diluted earnings (loss) per common share				
Income (loss) before cumulative effect of accounting change	$(0.78)	$ 0.17	$ 0.17	$(0.62)
Cumulative effect of accounting change, net of income taxes	—	—	—	(0.06)
Net income (loss)	$(0.78)	$ 0.17	$ 0.17	$(0.68)

[1] In the fourth quarter of 2000, we restated operating revenues for 1999 and 2000 due to the implementation of Emerging Issues Task Force Issue No. 99-19, *Reporting Revenue Gross as a Principal versus Net as an Agent*. For the first, second, and third quarters of 2000, operating revenues increased by $26 million, $23 million, and $38 million. For the first, second, third and fourth quarters of 1999, operating revenues increased by $23 million, $50 million, $34 million and $21 million. These adjustments had no impact on net income (loss) or earnings per share.

19. Supplemental Natural Gas and Oil Operations (Unaudited)

At December 31, 2000, we had leases for approximately 2.7 million net acres in 11 states, including Louisiana, New Mexico, Texas, Oklahoma, and Arkansas, as well as the Gulf of Mexico. We also have exploration and production rights in Turkey.

Capitalized costs relating to natural gas and oil producing activities and related accumulated depreciation, depletion, and amortization were as follows:

	December 31,	
	2000	1999
	(In millions)	
Natural gas and oil properties:		
Costs subject to amortization	$5,795	$5,285
Costs not subject to amortization	135	130
	5,930	5,415
Less accumulated depreciation, depletion, and amortization	4,412	4,154
	$1,518	$1,261

Costs incurred in natural gas and oil producing activities, whether capitalized or expensed, were as follows:

	Years Ended December 31,		
	2000	1999	1998
	(In millions)		
Property acquisition costs:			
Proved properties	$ 74	$ 3	$ 2
Unproved properties	41	45	48
Exploration costs	100	139	156
Development costs	269	178	375
Total costs	$484	$365	$581

Presented below is an analysis of the capitalized costs of natural gas and oil properties by year of expenditure that are not being amortized as of December 31, 2000, pending determination of proved reserves. Capitalized interest of $9 million, $12 million, and $2 million for the years ended December 31, 2000, 1999, and 1998 is included in the presentation below.

	Cumulative Balance	Costs Excluded for Years Ended Dec. 31			Cumulative Balance
	Dec. 31, 2000	2000	1999	1998	Dec. 31, 1997
		(In millions)			
Acquisition	$ 80	$45	$ 7	$19	$9
Exploration	55	28	19	8	—
	$135	$73	$26	$27	$9

Projects presently excluded from amortization are in various stages of evaluation. The majority of these costs are expected to be included in the amortization calculation in the years 2001 through 2004. Total amortization expense per Mcfe, including ceiling test charges, was $0.97, $2.54, and $4.81 in 2000, 1999 and 1998. Excluding ceiling test charges, amortization expense would have been $0.95 and $1.06 per Mcfe in 1999 and 1998.

Net quantities of proved developed and undeveloped reserves of natural gas and liquids, including condensate and crude oil, and changes in these reserves, were as follows:

	December 31,					
	2000		1999		1998	
	Gas (Bcf)	Liquids (MBbls)	Gas (Bcf)	Liquids (MBbls)	Gas (Bcf)	Liquids (MBbls)
Proved (developed and undeveloped) reserves, net:						
Beginning of year	1,271	30,438	1,423	29,717	2,161	72,882
Revisions of previous estimates	(46)	(814)	(65)	(336)	(349)	(12,816)
Extensions, discoveries, and other additions	437	4,966	188	10,599	119	1,688
Purchases of reserves in place	78	1,043	34	117	6	—
Sales of reserves in place	—	—	(123)	(3,834)	(288)	(23,710)
Production	(188)	(5,138)	(186)	(5,825)	(226)	(8,327)
End of year	1,552	30,495	1,271	30,438	1,423	29,717
Proved developed reserves:						
Beginning of year	967	19,713	1,123	24,743	1,558	45,225
End of year	1,061	18,640	967	19,713	1,123	24,743

There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting future rates of production and timing of development expenditures, including many factors beyond our control. The reserve data represents only estimates. Reservoir engineering is a subjective process of estimating underground accumulations of natural gas and oil that cannot be measured in an exact manner.

The significant changes to reserves, other than purchases, sales or production, are due to reservoir performance in existing fields and from drilling additional wells in existing fields. There have been no major discoveries or other events, favorable or adverse, that may be considered to have caused a significant change in the estimated proved reserves since December 31, 2000.

Results of operations from producing activities by fiscal year were as follows:

	Years Ended December 31,		
	2000	1999	1998
		(In millions)	
Net revenues:			
Sales to external customers	$ 298	$ 108	$ 174
Affiliated sales	224	365	361
Total	522	473	535
Production costs	(74)	(98)	(91)
Depreciation, depletion, and amortization	(212)	(210)	(292)
Ceiling test charges	—	(352)	(1,035)
Results of operations from producing activities before tax	236	(187)	(883)
Income tax (expense) benefit	(77)	71	315
Results of operations from producing activities (excluding corporate overhead and interest costs)	$ 159	$(116)	$ (568)

The standardized measure of discounted future net cash flows relating to proved natural gas and oil reserves follows:

	December 31,		
	2000	1999	1998
		(In millions)	
Future cash inflows	$16,923	$ 3,421	$ 3,124
Future production and development costs	(2,130)	(1,056)	(1,028)
Future income tax expenses	(4,870)	(458)	(317)
Future net cash flows	9,923	1,907	1,779
10% annual discount for estimated timing of cash flows	(3,870)	(656)	(617)
Standardized measure of discounted future net cash flows	$ 6,053	$ 1,251	$ 1,162

For the calculations in the preceding table, estimated future cash inflows from estimated future production of proved reserves were computed using year-end market natural gas and oil prices. We may receive amounts different than the standardized measure of discounted cash flow for a number of reasons, including price changes and the effects of our hedging activities.

The following are the principal sources of change in the standardized measure of discounted future net cash flows:

	Years Ended December 31,		
	2000	1999	1998
		(In millions)	
Sales and transfers of natural gas and oil produced, net of production costs	$ (448)	$(375)	$ (444)
Net changes in prices and production costs	5,398	297	(394)
Extensions, discoveries and improved recovery, less related costs	2,352	262	72
Changes in estimated future development costs	(422)	9	36
Development costs incurred during the period	180	58	182
Revisions of previous quantity estimates	(283)	(73)	(413)
Accretion of discount	153	127	269
Net change in income taxes	(2,673)	(166)	379
Purchases of reserves in place	443	37	4
Sales of reserves in place	—	(174)	(469)
Changes in production rates (timing) and other	102	87	(259)
	$ 4,802	$ 89	$(1,037)

REPORT OF INDEPENDENT ACCOUNTANTS

To the Board of Directors and Stockholders of
El Paso Corporation:

In our opinion, the consolidated financial statements listed in the index appearing under Item 14.(a) 1. present fairly, in all material respects, the consolidated financial position of El Paso Corporation as of December 31, 2000 and 1999, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2000, in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the index appearing under Item 14.(a) 2. presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. These financial statements and the financial statement schedule are the responsibility of the Company's management; our responsibility is to express an opinion on these financial statements and the financial statement schedule based on our audits. We conducted our audits of these statements in accordance with auditing standards generally accepted in the United States of America, which 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, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

PricewaterhouseCoopers LLP

Houston, Texas
March 20, 2001

SCHEDULE II

EL PASO CORPORATION
VALUATION AND QUALIFYING ACCOUNTS

Years Ended December 31, 2000, 1999, and 1998
(In millions)

Description	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts	Deductions	Balance at End of Period
2000					
Allowance for doubtful accounts	$33	$ 92	$(1)	$(13) [(a)]	$111
Allowance for price risk management activities	39	157	—	(3) [(b)]	193
Valuation allowance on deferred tax assets	6	—	—	(3)	3
1999					
Allowance for doubtful accounts	$32	$ 10	$(2)	$ (7) [(a)]	$ 33
Allowance for price risk management activities	28	21	—	(10) [(b)]	39
Valuation allowance on deferred tax assets	5	—	1	—	6
1998					
Allowance for doubtful accounts	$52	$ —	$ 6	$(26) [(a)]	$ 32
Allowance for price risk management activities	25	23	—	(20) [(b)]	28
Valuation allowance on deferred tax assets	19	—	4	(18) [(c)]	5

(a) Primarily accounts written off.

(b) Primarily liquidation of positions on which allowance was established.

(c) $11 million of this deduction was credited to additional paid-in capital for the utilization of Zilkha Energy Company's net operating loss (NOL) carryforward and $7 million was credited to deferred tax assets for a waiver of Gulf States Gas Pipeline Company's NOL carryforward.

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

None.

PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

The information under the captions "Proposal No. 1 — Election of Directors" and "Section 16(a) Beneficial Ownership Reporting Compliance" in our proxy statement for the 2001 Annual Meeting of Stockholders is incorporated herein by reference. Information regarding our executive officers is presented in Item 1, Business, of this Form 10-K under the caption "Executive Officers of the Registrant."

ITEM 11. EXECUTIVE COMPENSATION

Information appearing under the caption "Executive Compensation" in our proxy statement for the 2001 Annual Meeting of Stockholders is incorporated herein by reference.

ITEM 12. SECURITY OWNERSHIP OF MANAGEMENT

Information appearing under the caption "Security Ownership of Certain Beneficial Owners and Management" in our proxy statement for the 2001 Annual Meeting of Stockholders is incorporated herein by reference.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

None.

PART IV

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

(a) The following documents are filed as a part of this report:

1. Financial statements.

Our consolidated financial statements are included in Part II, Item 8 of this report:

2. Financial statement schedules and supplementary information required to be submitted.

Schedules other than that listed above are omitted because they are not applicable.

(b) Reports on Form 8-K:

- We filed a current report on Form 8-K, dated October 18, 2000 filing exhibits in connection with an offering of medium term notes pursuant to a Registration Statement on Form S-3.

- We filed a current report on Form 8-K, dated December 6, 2000, updating pro forma financial statements relating to the proposed merger with The Coastal Corporation.

- We filed a current report on Form 8-K, dated December 8, 2000, filing exhibits in connection with an offering of medium term notes pursuant to a Registration Statement on Form S-3.

- We filed a current report on Form 8-K, dated December 19, 2000, filing exhibits in connection with an offering of medium term notes pursuant to a Registration Statement on Form S-3.

- We filed a current report on Form 8-K, dated January 3, 2001, announcing the completion of our acquisition of PG&E's Texas Midstream operations.

- We filed a current report on Form 8-K, dated January 29, 2001, announcing the completion of our merger with The Coastal Corporation.

- We filed a current report on Form 8-K, dated February 5, 2001, announcing the completion of our merger with The Coastal Corporation and the exchange and issuance of shares of El Paso.

- We filed a current report on Form 8-K, dated February 6, 2001, announcing our name change to El Paso Corporation.

- We filed a current report on Form 8-K, dated February 14, 2001, announcing several events including the opening of a New European Trading floor, the Purchase of Texas Midstream Operations, Recent Developments on California, the Approval of a Dividend Increase, the Announcement of Record Earnings, the Completion of Post Merger Restructuring, and our 2001 Analysts Meetings.

- We filed a current report on Form 8-K/A, dated February 21, 2001 announcing information on debt issuances and clarifying items contained in the February 14, 2001 Form 8-K.

- We filed a current report on Form 8-K, dated February 23, 2001 announcing plans to offer a private offering of zero coupon convertible debentures, convertible into El Paso common stock.

- We filed a current report on Form 8-K, dated March 2, 2001, announcing our combined operating results for the first 30 days following our merger with Coastal.

EL PASO CORPORATION

EXHIBIT LIST
December 31, 2000

Each exhibit identified below is filed as a part of this report. Exhibits not incorporated by reference to a prior filing are designated by an asterisk; all exhibits not so designated are incorporated herein by reference to a prior filing as indicated. Exhibits designated with a "+" constitute a management contract or compensatory plan or arrangement required to be filed as an exhibit to this report pursuant to Item 14(c) of Form 10-K.

Exhibit Number	Description
2	— Agreement and Plan of Merger, dated January 17, 2000, by and among El Paso, El Paso Merger Company and The Coastal Corporation (Exhibit 1 to Schedule 13D filed by El Paso on January 26, 2000, File No. 5-55241).
3.A	— Restated Certificate of Incorporation of El Paso as filed with the Delaware Secretary of State on February 7, 2001 (Exhibit 3.A to El Paso's Form 8-K, filed February 14, 2001).
3.B	— Restated By-laws of El Paso (Exhibit 3.B to El Paso's Form 8-K dated February 14, 2001).
4.A	— Amended and Restated Shareholder Rights Agreement, between El Paso and BankBoston, N.A., dated January 20, 1999 (Exhibit 1 to El Paso's Registration Statement on Form 8-A/A Amendment No. 1, filed January 29, 1999, File No. 1-14365).
4.B	— Indenture dated as of May 10, 1999, by and between the Registrant and The Chase Manhattan Bank, as Trustee (Exhibit 4.1 to El Paso Form 8-K dated May 10, 1999, File No. 1-14365).
*4.C	— Fifth Supplemental Indenture dated as of February 28, 2001, by and between El Paso and The Chase Manhattan Bank, as Trustee, including the form of Zero Coupon Convertible Debenture due February 28, 2001.
*4.D	— Form of Purchase Contract Agreement between The Coastal Corporation and The Bank of New York as Purchase Contract Agent and First Supplement to the Purchase Agreement dated as of January 29, 2001 among The Coastal Corporation, El Paso and The Bank of New York, as Purchase Contract Agent.
10.A	— $2,000,000,000 364-Day Revolving Credit and Competitive Advance Facility Agreement dated August 4, 2000, by and among El Paso, EPNG, TGP, the several banks and other financial institutions from time to time parties to the Agreement, The Chase Manhattan Bank, Citibank N.A. and ABN Amro Bank, N.V. as co-documentation agents for the Lenders and Bank of America, N.A. as syndication agent for the Lenders (Exhibit 10.A to El Paso's 2000 Third Quarter 10-Q).
10.B	— $1,000,000,000 3-Year Revolving Credit and Competitive Advance Facility Agreement dated August 4, 2000, by and among El Paso, EPNG, TGP, the several banks and other financial institutions from time to time parties to the Agreement, The Chase Manhattan Bank, Citibank N.A., ABN Amro Bank, N.V. as co-documentation agents for the Lenders and Bank of America, N.A. as syndication agent for the Lenders (Exhibit 10.B to El Paso's 2000 Third Quarter 10-Q).
*10.B.1	— $700,000,000 3-Month Revolving Credit Facility Agreement dated as of December 21, 2000 among El Paso, the several banks and other financial institutions, The Chase Manhattan Bank, as administrative agent for the Lenders and Chase Securities Inc. as lead arranger and book manager.

Exhibit Number	Description
+10.C	— Omnibus Compensation Plan dated January 1, 1992; Amendment No. 1 effective as of April 1, 1998; Amendment No. 2 effective as of August 1, 1998; Amendment No. 3 effective as of December 3, 1998; and Amendment No. 4 effective as of January 20, 1999 (Exhibit 10.C to El Paso's 1998 10-K).
+10.D	— 1995 Incentive Compensation Plan, Amended and Restated effective as of December 3, 1998 (Exhibit 10.D to El Paso's 1998 10-K).
+10.E	— 1995 Compensation Plan for Non-Employee Directors, Amended and Restated effective as of August 1, 1998 (Exhibit 10.H to El Paso's 1998 Third Quarter 10-Q); Amendment No. 1, effective March 9, 1999, (Exhibit 10.E.1 to El Paso's 1999 Second Quarter 10-Q) and Amendment No. 2, effective as of July 16, 1999 (Exhibit 10.E.2 to El Paso's 1999 Second Quarter 10-Q).
+10.F	— Stock Option Plan for Non-Employee Directors, Amended and Restated effective as of January 20, 1999 (Exhibit 10.F to El Paso's 1998 10-K) and Amendment No. 1, effective as of July 16, 1999 (Exhibit 10.F.1 to El Paso's 1999 Second Quarter 10-Q).
+10.G	— 1995 Omnibus Compensation Plan, Amended and Restated effective as of August 1, 1998 (Exhibit 10.J to El Paso's 1998 Third Quarter 10-Q); Amendment No. 1, effective as of December 3, 1998; and Amendment No. 2, effective as of January 20, 1999 (Exhibit 10.G.1 to El Paso's 1998 10-K).
+10.H	— Supplemental Benefits Plan, Amended and Restated effective as of December 3, 1998 (Exhibit 10.H to El Paso's 1998 10-K), and Amendment No. 1 effective as of January 1, 2000 (Exhibit 10.H.1 to El Paso's 2000 Second Quarter 10-Q).
+10.I	— Senior Executive Survivor Benefit Plan, Amended and Restated effective as of August 1, 1998 (Exhibit 10.M to El Paso's 1998 Third Quarter 10-Q).
+10.J	— Deferred Compensation Plan, Amended and Restated effective as of December 3, 1998. (Exhibit 10.J to El Paso's 1998 10-K), and Amendment No. 1 effective as of January 1, 2000 (Exhibit 10.K.1 to El Paso's 2000 Second Quarter 10-Q).
+10.K	— Key Executive Severance Protection Plan, Amended and Restated effective as of August 1, 1998 (Exhibit 10.O to El Paso's 1998 Third Quarter 10-Q).
+10.L	— Director Charitable Award Plan, Amended and Restated effective as of August 1, 1998 (Exhibit 10.P to the El Paso's 1998 Third Quarter 10-Q).
+10.M	— Strategic Stock Plan, Amended and Restated effective as of December 31, 1999 (Exhibit 10.1 to El Paso's Form S-8 filed January 14, 2000).
+10.N	— Domestic Relocation Policy, effective November 1, 1996 (Exhibit 10.Q to EPNG's Form 10-K, filed March 20, 1998, File No. 1-2700).
*+10.O	— Employment Agreement, Amended and Restated effective as of February 1, 2001, between El Paso and William A. Wise.
+10.Q	— Promissory Note dated May 30, 1997, made by William A. Wise to El Paso (Exhibit 10.R to EPNG's Form 10-Q, filed May 15, 1998, File No. 1-2700 ("EPNG's 1998 First Quarter 10-Q"); Amendment to Promissory Note dated November 20, 1997 (Exhibit 10.R to EPNG's 1998 First Quarter 10-Q).
+10.R	— Executive Award Plan of Sonat Inc., amended and restated effective as of July 23, 1998, as amended May 27, 1999 (Exhibit 10.R to El Paso's 1999 Third Quarter 10-Q); Termination of the Executive Award Plan of Sonat Inc. (Exhibit 10.K.1 to El Paso's 2000 Second Quarter 10-Q).

Exhibit Number	Description
+10.S	— Letter Agreement dated February 22, 1991, between EPNG and Britton White Jr. (Exhibit 10.V to the El Paso's 1998 Third Quarter 10-Q).
+10.T	— El Paso Employee Stock Purchase Plan, effective as of January 20, 1999 (Exhibit 10.1 to El Paso's Form S-8, filed May 20, 1999, File No. 333-78949); Amendment No. 1, effective as of May 24, 1999.
*+10.T.1	— Amendment No. 2 to the El Paso Employee Stock Purchase Plan effective as of October 1, 1999; Amendment No. 3 to the Employee Stock Purchase Plan effective as of March 14, 2000 and Amendment No. 4 to the Employee Stock Purchase Plan effective as of January 1, 2001.
+10.U	— Omnibus Plan for Management Employees Amended and Restated effective as of December 3, 1999 (Exhibit 10.1 to El Paso's Form S-8 filed January 14, 2000, File No. 333-94719) and Amendment No. 1 effective as of December 1, 2000 (Exhibit 10.1 to El Paso's Form S-8 filed December 18, 2000).
+10.V	— 1999 Omnibus Incentive Compensation Plan, dated January 20, 1999 (Exhibit 10.1 to El Paso's Form S-8 filed May 20, 1999).
*+10.W	— Employment Letter dated June 16, 1999, between El Paso and Ralph Eads.
*+10.X	— Termination and Consulting Agreement dated October 25, 1999, between El Paso and Ronald L. Kuehn Jr.
*10.Y	— Form of Stock Pledge Agreement, dated February 1, 2001, by and between El Paso and the named executives therein; and Form of Promissory Note dated February 1, 2001, in favor of El Paso by named executives therein; and listing of certain executive participants.
*+10.Z	— Professional Services Agreement dated January 16, 2001 by and between El Paso and David A. Arledge.
*21	— Subsidiaries of El Paso.
*23	— Consent of Independent Accountants.

Undertaking

We hereby undertake, pursuant to Regulation S-K, Item 601(b), paragraph (4)(iii), to furnish to the Securities and Exchange Commission upon request all constituent instruments defining the rights of holders of our long-term debt and our consolidated subsidiaries not filed herewith for the reason that the total amount of securities authorized under any of such instruments does not exceed 10 percent of our total consolidated assets.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, as amended, El Paso Corporation has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized on the 21st day of March 2001.

EL PASO CORPORATION
Registrant

By /s/ WILLIAM A. WISE

William A. Wise
Chairman of the Board,
President and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, as amended, this report has been signed below by the following persons on behalf of El Paso Corporation and in the capacities and on the dates indicated:

Signature	Title	Date
/s/ WILLIAM A. WISE (William A. Wise)	Chairman of the Board, President, Chief Executive Officer and Director	March 21, 2001
/s/ H. BRENT AUSTIN (H. Brent Austin)	Executive Vice President and Chief Financial Officer	March 21, 2001
/s/ JEFFREY I. BEASON (Jeffrey I. Beason)	Senior Vice President and Controller (Chief Accounting Officer)	March 21, 2001
/s/ BYRON ALLUMBAUGH (Byron Allumbaugh)	Director	March 21, 2001
/s/ DAVID A. ARLEDGE (David A. Arledge)	Director	March 21, 2001
/s/ JOHN M. BISSELL (John M. Bissell)	Director	March 21, 2001
/s/ JUAN CARLOS BRANIFF (Juan Carlos Braniff)	Director	March 21, 2001
/s/ JAMES F. GIBBONS (James F. Gibbons)	Director	March 21, 2001
/s/ ANTHONY W. HALL JR. (Anthony W. Hall Jr.)	Director	March 21, 2001
/s/ RONALD L. KUEHN, JR. (Ronald L. Kuehn, Jr.)	Director	March 21, 2001

Signature	Title	Date
/s/ J. CARLETON MACNEIL JR. (J. Carleton MacNeil Jr.)	Director	March 21, 2001
/s/ THOMAS R. MCDADE (Thomas R. McDade)	Director	March 21, 2001
/s/ MALCOLM WALLOP (Malcolm Wallop)	Director	March 21, 2001
/s/ JOE B. WYATT (Joe B. Wyatt)	Director	March 21, 2001